For Reference

NOT TO BE TAKEN FROM THIS ROOM

For Reference

NOT TO BE TAKEN FROM THIS ROOM

Ex libris
universitatis
albertaensis

University of Alberta
Printing Department

Digitized by the Internet Archive
in 2018 with funding from
University of Alberta Libraries

https://archive.org/details/displacementofhi00wint

Thesis
1960
#46

THE UNIVERSITY OF ALBERTA

"DISPLACEMENT OF HIGH VISCOSITY OIL BY A WATER-DRIVEN MISCIBLE SLUG"

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR
THE DEGREE OF MASTER OF SCIENCE IN PETROLEUM ENGINEERING

FACULTY OF ENGINEERING

DEPARTMENT OF CHEMICAL AND PETROLEUM ENGINEERING

by

C. R. WINTER

Edmonton, Alberta April, 1960

ACKNOWLEDGEMENTS

The final presentation of this thesis was made possible through the generous assistance offered by many interested individuals and organization. Space does not permit recognition of all contributions however mention must be made of the more outstanding ones. Acknowledgement is extended to Dr. D. L. Flock who contributed encouragement, advice and guidance from the outset of the project; to Mr. E. M. Blanchard of Alberta Oil Tool Ltd., who helped provide equipment; to Mr. Frank Butz and Mr. Heinz Tablemann who assisted in the construction of the equipment; and to Mr. Ferris Swann of Gas Test Engineering Ltd. whose generosity allowed the writer to spend many extra hours on the project.

Particularly grateful acknowledgement is extended to those of the staff of Trans-Canada Pipe Lines Limited, Calgary who assisted with the typing and drafting and especially to Mr. E. M. Foo under whose authority this assistance was made possible.

ABSTRACT

An experimental investigation has been conducted to investigate the mechanism of displacement of a high viscosity oil from an unconsolidated proous system using varying size miscible butane slugs, and an immiscible driving phase, water. A waterflood was carried out under identical conditions to be used as a basis of comparison for the solvent slug runs.

The pressure profiles along the core for various uniform time increments throughout each run have been plotted and are presented and discussed. A comparison of the recovery of oil at water breakthrough and at abandonment for the various slug sizes is included.

Experimental results indicate that mobility ratio is a very dominant factor in controlling recovery at breakthrough. Results also indicate that for the conditions investigated there is a critical slug size below which no decrease in time of breakthrough is experienced and above which no material increase in recovery of oil at breakthrough is achieved.

TABLE OF CONTENTS

	Page No.
Abstract	(ii)
Acknowledgements	(iii)
List of Tables	(v)
List of Figures	(vi)
INTRODUCTION	1
LITERATURE REVIEW	4
EXPERIMENTAL EQUIPMENT	10
EXPERIMENTAL PROCEDURE	12
EXPERIMENTAL RESULTS AND DISCUSSION	14
SUMMARY AND CONCLUSIONS	27
RECOMMENDATIONS	30
BIBLIOGRAPHY	31
APPENDIX	33

LIST OF TABLES

Table		Page No.
1	Percent Recovery of Oil with Time	15
1-A	Recorded Data: Run Number 2	Appendix
2-A	Recorded Data: Run Number 3	Appendix
3-A	Recorded Data: Run Number 4	Appendix
4-A	Recorded Data: Run Number 5	Appendix
5-A	Recorded Data: Run Number 6	Appendix
6-A	Recorded Data: Run Number 8	Appendix
7-A	Recorded Data: Run Number 9	Appendix
8-A	Recorded Data: Run Number 10	Appendix

LIST OF FIGURES

Figure		Page No.
1	Schematic Diagram of Experimental Equipment	9
2	Pressure Profile Diagram; Waterflood	17
3	Pressure Profile Diagram: 6% Slug	18
4	Recovery of Oil in Place vs Time	19
5	Recovery of Oil in Place at Water Breakthrough vs Butane Slug Size	23
6	Recovery of Oil in Place at Total Fluid Production of Two Pore Volumes vs Butane Slug Size	25
1-A	Typical Relative Permeability Curve for Unconsolidated Sand	Appendix
2-A	Working Curve for Waterflood Breakthrough Recovery Calculation	Appendix
3-A	Calculated Recovery at Breakthrough vs Viscosity Ratio	Appendix
4-A	Pressure Profile Diagram: Waterflood	Appendix
5-A	Pressure Profile Diagram: 1% Slug	Appendix
6-A	Pressure Profile Diagram: 1% Slug	Appendix
7-A	Pressure Profile Diagram: 2% Slug	Appendix
8-A	Pressure Profile Diagram: 3% Slug	Appendix
9-A	Pressure Profile Diagram: 4% Slug	Appendix
10-A	Pressure Profile Diagram: 6% Slug	Appendix
11-A	Pressure Profile Diagram: 8% Slug	Appendix

INTRODUCTION

It is well known within the petroleum industry that vast quantities of oil are beyond economic recovery using present day techniques. From 25% to 50% of all oil discovered will remain in the ground as residual oil upon abandonment. This fact is known but is not accepted as being inevitable within the industry. Much is being done to increase recovery factors and thus increase our recoverable reserves of oil.

It has long been recognized that the most efficient method of recovering oil from a porous media is by reducing the capilliary and interfacial forces to essentially zero by means of a miscible solvent and displacing the oil. Recently, research organizations and producing companies have placed great emphasis upon secondary recovery projects based on this principle. Out of this great complexity of research data has come the miscible drive process with its various modifications.

This type of process became economically feasible when it was found that vast quantities of solvent were not required but that a relatively small quantity of L.P.G.* could be maintained as a bank or buffer zone between the reservoir oil and a subsequently injected relatively inexpensive gas phase. Conditions are maintained such that the solvent bank is completely miscible with both the reservoir oil and the dry gas phase thus

---

* Liquefied petroleum gas

affecting a miscible phase drive of a reservoir oil with a gas. The various techniques employed in accomplishing this type of displacement now in use include miscible slug, enriched or condensing gas drive, high pressure gas injection and solvent flooding. These are outlined briefly below.

(a) Miscible Slug - An explicit slug of liquefied petroleum gas, introduced into the reservoir initially, is driven toward the producing wells using a secondary phase, usually dry gas, under conditions which promote its miscibility with the L.P.G.

(b) Enriched or Condensing Gas Drive - In this process gas rich in intermediate components (C_2 - C_6) is injected into the reservoir under such conditions as will cause a large portion of these intermediate components to condense upon contact with the reservoir oil, thus forming a low viscosity solvent bank. This bank, in turn, is propelled toward the producing wells by means of the remaining and subsequently injected uncondensed gas.

(c) High Pressure Gas Injection - Lean gas, injected into the reservoir under very high pressures, absorbs intermediate weight hydrocarbons (C_2 - C_6) from the reservoir oil contacted. This enrichment continues until a miscible bank is built up at the flood front which thereafter sweeps the reservoir oil ahead of it. This process differs from the Condensing Gas Drive chiefly in the range of operating pressures

required and the type of gas employed.

(d) Solvent Flooding - In this process the reservoir is actually flooded with solvent. Some provision must be made for recovery of the solvent such as waterflood or cycling.

As the miscible phase displacement became recognized as a means of secondary recovery and began to be applied to field cases, various problems arose. Perhaps the most serious difficulty encountered is the low areal or sweep efficiency afforded. This is caused primarily by the adverse mobility ratio, however, it is greatly aggravated by permeability variations. A second problem, economic rather than technical, is that despite greatly increased recoveries a project may not prove economically attractive due primarily to the price commanded by the L.P.G. required. These difficulties often indicate that some other secondary recovery mechanism be utilized.

At the time of initiation of this study no published data wereavailable on the effect of following a miscible phase slug with a waterflood. It was reasoned that use of water as a secondary phase would result in a combining of the beneficial effects of both the miscible displacement mechanism and the waterflood. The solvent bank would yield high displacement efficiency and the water would affect a higher areal sweepout resulting in an increased overall recovery.

This research project was thus chosen to study the mechanism of this displacement in a linear model in an attempt to evaluate its applicability to oil reservoirs.

LITERATURE REVIEW

Many articles [1, 8, 9, 10, 11, 13, 14 17, 18,] are available on miscible displacement studies and a complete review of this literature is neither necessary nor warranted here. Round [16] has presented a comprehensive review of this material. However, some of the basic concepts established by the various investigators will be reiterated as a basis for our thinking on this project.

Connally and Mason [6] and Justin et al [12] in separate analyses of the pilot miscible flood of a 10-acre, 5-spot in the Pembina field indicate that permeability stratification had a marked effect on breakthrough and subsequent performance and that the poor sweep efficiency experienced was partially alleviated by injection of slugs of water into the partially swept reservoir. Recovery in the order of 75% was realized as compared to a waterflood recovery of 30%. A 7% pore volume L. P. G. slug was used . Blackwell, Rayne and Terry [2] also found that permeability stratification had a very adverse effect on recovery. They calculated a typical mixing zone length to be 1/3 foot for geometric conditions similar to those used here with the exception that they used fluids of matched viscosities and densities.

Viscosity ratio has been widely discussed and is probably the most important factor influencing recovery. Brigham, Reed and Dow [3] found that in changing from a favourable

to an adverse viscosity ratio the dispersion rate was disproportionately increased and the effluent concentration curve was greatly extended indicating viscous fingering. They assumed that the dispersion rate was directly proportional to the viscosity ratio. Handy[10] concluded that molecular diffusion was insignificant and that viscosity ratio was the governing factor controlling the amount of dispersion in the mixed zone. Blackwell, Rayne and Terry[2] found that viscosity ratio was a major factor in determining both recovery and quantity of solvent required. Offeringa and Van der Poel[15] suggested that breakthrough recoveries are a function of viscosity ratio chiefly but refuted the formerly accepted idea that the formation of a transition zone would result in a "plunger" type displacement in cases where an adverse mobility ratio existed. They indicated that in such cases viscous fingering would predominate and lower recoveries than those predicted by other investigators would result.

Gravity effects were found to be important by Lacey, Draper and Binder[14] especially in cases where reservoir dip was encountered. Blackwell, Rayne and Terry[2] agree.

Model dimensions and rate have been discussed by many researchers. Offeringa and Van der Poel[15] suggest there is a minimum size of model below which reliable results cannot be obtained. Lacey, Draper and Binder[14] and Blackwell, Rayne and

Terry[2] agree but all differ as to the critical size. Important considerations are length, length to width ratio and diameter. Rate or more precisely pore velocity may influence recovery, but it is generally agreed that it is insignificant if molecular diffusion is low, which is normally the case in liquid-liquid displacement.

Quantity of solvent is a very important economic factor and there is some dissension as to its importance. Most investigators[5, 13, 14] feel that slug size has little effect above that critical size required to maintain miscibility over the length of the model. Koch and Slobod[13] suggest that the required slug size is directly proportional to the square root of the path length. Other workers[2, 5, 15] suggest that in most cases the solvent only acts as a diluent in reducing the viscosity of the reservoir oil thus bringing about increased recovery through a reduction in viscosity ratio.

Two experimental projects, being somewhat similar to this project will be discussed in detail. They are the investigations of Caudle and Dyes[7] and of Cole, Cowan and Jackson[5]. Caudle and Dyes attempted to take advantage of the lower mobility of water by injecting gas-water mixtures behind a solvent slug. They reasoned that regions of the reservoir swept by the solvent would accommodate such a large gas flow that channelling would occur resulting in poor areal efficiency. They attempted to plug these channels or at least lower the relative permeability to gas by the use of water. Sub-

stantially better areal sweepout of a 5-spot pattern was affected. However, the areal sweepout was still less than that achieved by waterflood, for viscosity ratios approaching unity.

Cole, Cowan and Jackson injected varying sizes of pentane slugs in advance of waterflooding radial core systems. Their results showed that there is usually an optimum slug size to inject ahead of a waterflood although essentially complete recovery of oil in place could be achieved if sufficiently large solvent slugs were used. However, they were unable to reduce the residual hydrocarbon content of their cores below about 30% (in reality an exchange of pentane for oil) indicating that the solvent was fingering through the oil quite drastically in the initial stages of the project and in the final stages the water was following these low viscosity channels to early break through. (The latter paper was published after this research project was completed).

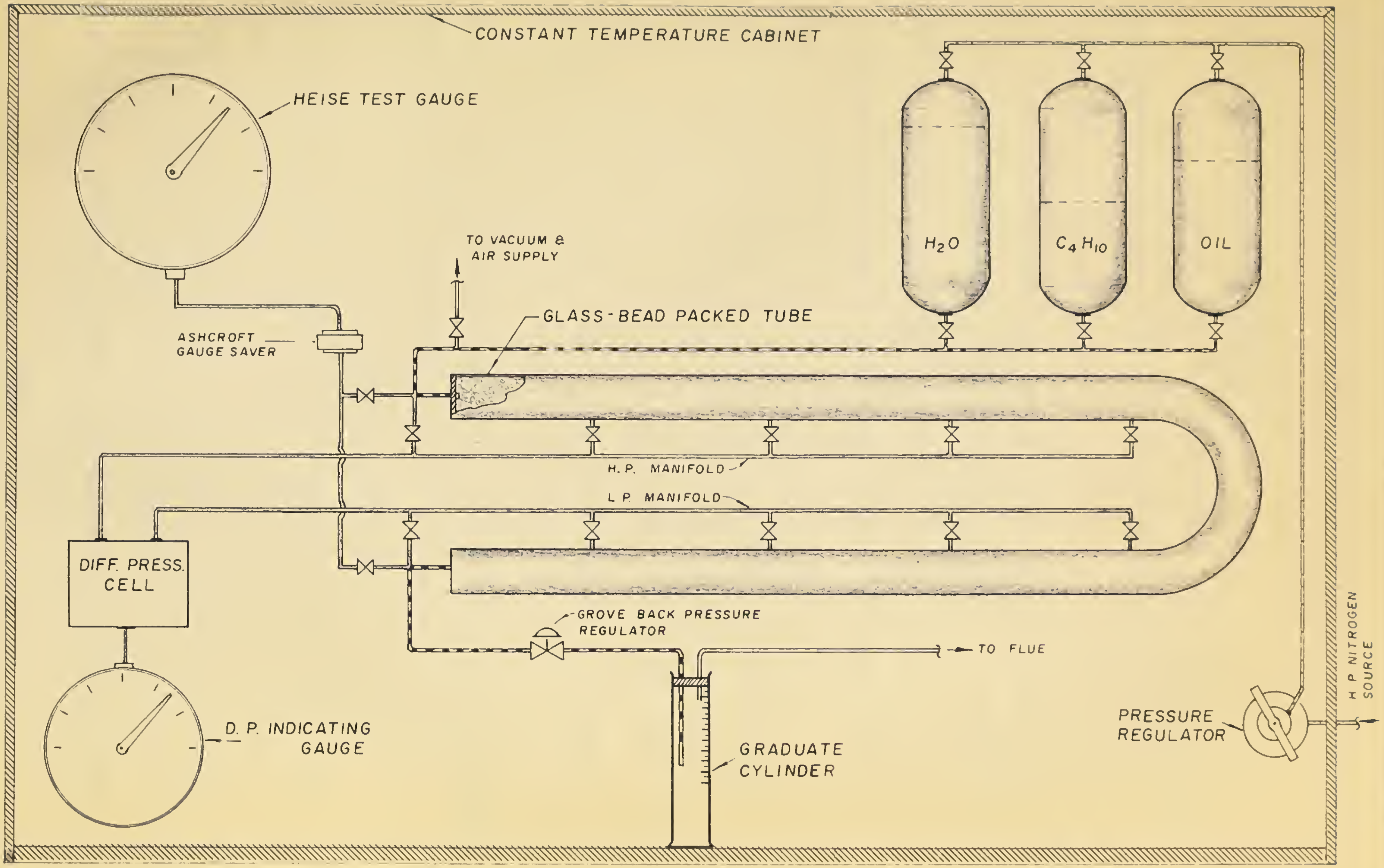


FIGURE I - SCHEMATIC DIAGRAM OF EXPERIMENTAL EQUIPMENT

EXPERIMENTAL EQUIPMENT

Figure I is a schematic diagram of the experimental equipment used in this project. The simulated reservoir consisted of a U-shaped steel tube packed with glass beads, made up of equal quantities of 100 mesh and 200 mesh beads forming a pack having a porosity of 17.9% and an absolute permeability of 2.34 darcys. Tube length was 236 cms and diameter was 4.925 cms. One-eighth inch copper tube pressure taps were tapped into the core providing ten pressure measurement stations equally spaced along the core. The five upstream taps were valved into a "High Side" manifold and the five lower taps were manifolded into a "Low Side" manifold. The manifolds in turn were connected into the high and low sides of a flooded Foxboro pneumatic differential pressure cell (D-P cell). By suitable manipulation of the valves and by difference measurements the pressure differential across any two taps could be read in inches of water, as indicated directly by the D-P cell gauge. Core inlet and outlet pressures were measured with a Heise test gauge. Flow was actuated by means of high pressure regulated-supply nitrogen displacement of the fluids. Constant pressure in the system was maintained by means of a Grove pre-charged dome back pressure regulator. Measurement of the effluent was

made in a graduate cylinder. The entire system except for the gauges and valves was enclosed in a constant temperature cabinet maintained at a temperature of 120 ± 2°F.

EXPERIMENTAL PROCEDURE

The core was prepared for each run by flushing it with three or four pore volumes of butane and then air drying for a period of from 24 to 36 hours. The core was then evacuated to within 0.1 mm of H_g of current barometer reading and saturated with distilled water under pressure. The water was then displaced from the core using the reservoir oil. This procedure achieved an average residual or "connate" water saturation of 5.5%, the remainder of the 800 cc pore volume being filled with the 40.39 cps reservoir oil ('Primol "D" ' - Refined white mineral oil). Having established virgin conditions, the equipment was now in readiness for an experimental run.

An experimental run was carried out as follows: After taking an initial pressure profile and adjusting the inlet and outlet regulators, butane, in liquid form, was admitted to the core. Since there was no free gas saturation within the cores, the amount of liquid produced from the core was equal to the amount admitted to the core. Thus the effluent oil was measured and when the desired slug size had been produced the butane inlet valve was closed and the water inlet valve opened. An explicit butane slug was now in place in the inlet end of the core, being driven toward the outlet or producing end by a water phase. The total

differential pressure across the core was maintained at 50 psi. Volumes, temperature in the cabinet, inlet and outlet, pressures and differential pressures across the various pressure taps were recorded versus time for each run. Water breakthrough volumes and times were also recorded. All runs were terminated at a total fluid production of 2 pore volumes, at which time the effluent was approximately 95% water.

The core was then cleaned, flushed and resaturated as previously described in preparation for the next run.

The above described runs were carried out using butane slugs varying in size from 0 to 8% pore volume, the zero percent run being a waterflood was used as a reference run.

EXPERIMENTAL RESULTS AND DISCUSSION

The experimental results are tabulated and plotted both in this section and in the appendix. Recovery versus time data are tabulated in Table I and plotted on Figure 4. Recovery at water-breakthrough and at abandonment (completion of run) are plotted versus solvent slug size in Figures 5 and 6 and shown in Table I. Complete sets of pressure profile data taken every half hour during each run are included in Figures 4-A to 11-A and Tables 1-A to 8-A in the appendix. Samples of this information, Figures 2 and 3, are included in this section and discussed here.

A standard waterflood calculation of recovery at breakthrough based on the principles originally set forth by Buckley and Leverett[4] was carried out on this bead pack and is presented in the appendix. The assumptions required are that there is no water moving ahead of the flood front and that the relative movement of oil and water behind the flood front is governed by relative permeability and viscosity ratio relationships. A typical relative permeability curve, Figure 1-A, for an unconsolidated sand having a permeability similar to the core involved was utilized. The actual viscosity ratio, under experimental conditions, of the oil and water used was 72.6.

The calculation does not result in a direct figure for recovery at breakthrough but rather yields a plot of recovery of oil at breakthrough (residual water saturation) versus viscosity ratio.

TABLE I

PERCENT RECOVERY OF OIL WITH TIME *

Run No.	2	3	4	5	6	8	9	10
Time								
0.5	3.6	4.5	2.8	3.7	4.0	3.6	2.9	2.5
1.0	7.0	8.7	6.3	6.3	8.0	6.7	6.0	5.6
1.5	9.8	13.6	11.1	10.2	13.3	9.9	9.4	8.6
2.0	13.6	21.0	21.2	19.8	19.7	13.3	12.8	11.9
2.5	17.4	27.9	29.1	27.8	27.0	16.8	16.7	15.7
3.0	21.1	34.5	35.9	34.7	35.1	20.6	20.6	19.9
3.5	25.1	42.0	44.1	41.5	46.3	24.4	25.1	24.2
4.0	30.1	50.2	51.2	50.3	53.0	38.9	29.8	29.6
4.5	36.1	54.5	53.8	53.7	55.6	34.2	36.4	37.2
5.0	45.7	57.5	58.4	55.0	59.0	41.2	44.0	47.4
5.5	52.6	60.0	58.6	55.2	61.0	48.5	47.0	51.2
6.0	55.4	62.0	61.9	56.3	63.2	51.1	48.7	54.0
6.5	58.7	63.8	63.0	57.7	64.7	53.2	50.0	56.1
7.0	61.3	64.6	63.5	58.3	65.7	56.0	52.9	57.7
Butane Slug (% Pore Volume)	1%	4%	6%	8%	3%	1%	0%	2%
Breakthrough Time (hours)	4.92	3.92	3.58	3.98	3.58	5.22	4.75	4.92
Breakthrough (Recovery (% O.I.P.))	45.1%	48.7%	46.6%	50.3%	48.3%	45.7%	41.7%	47.2%
Total Time of Run (hours)	7.50	6.62	6.28	6.42	5.87	7.63	7.83	7.33
Total Recovery ** (% O.I.P.)	61.3%	64.1%	61.9%	59.1%	62.9%	58.3%	56.9%	60.4%

* Oil volumes corrected for butane content (See Page A-1 Appendix)

** Total Recovery = oil recovery when total production reached 2 pore volumes

This plot along with the working graph required appears in the appendix, Figure 2-A and 3-A. The final plot, Figure 3-A, shows that for the viscosity ratio that existed during the experimental run, 72.6, the oil recovery at breakthrough should be 43.2% of oil in place. This figure is considered to be in excellent agreement with the actual experimental recovery of 41.7%.

The aforementioned calculation was carried out primarily as a check on the equipment and procedure. Runs number 2 and 8 are duplicate 1% runs also used to check the reproducibility of the results, and it can be seen from Table I that the breakthrough recoveries agree very well. Verification of the accuracy of the experimental results serves to indicate that the displacement was obeying basic principles and that the model size was such that it had no appreciable adverse effect on the reliability of results and further that any set of results could be reproduced if run conditions were duplicated.

Figure 4 is a plot of percent recovery of original oil in place versus time for the various runs conducted. (Note that oil volumes have been corrected for any butane remaining in solution in the oil by means of equilibrium ratios). It is significant to note the sharp division between the small slug size runs and those using the larger slug volumes, particularly in the period before breakthrough. The major break comes between the 2% and the 3% curves. The results indicate that at this critical slug size, a small change

FIG. 2 RUN No. 9 WATERFLOOD

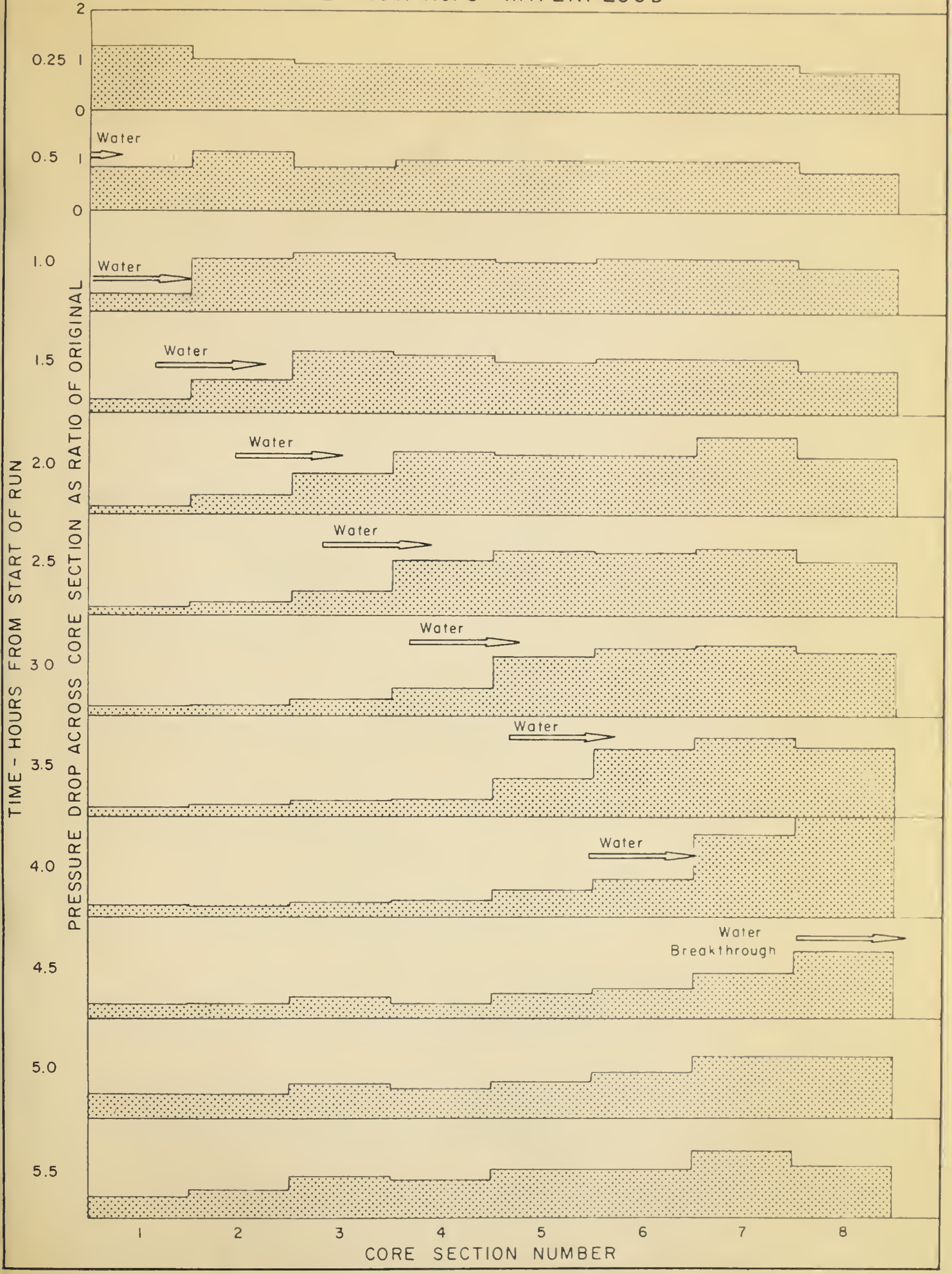
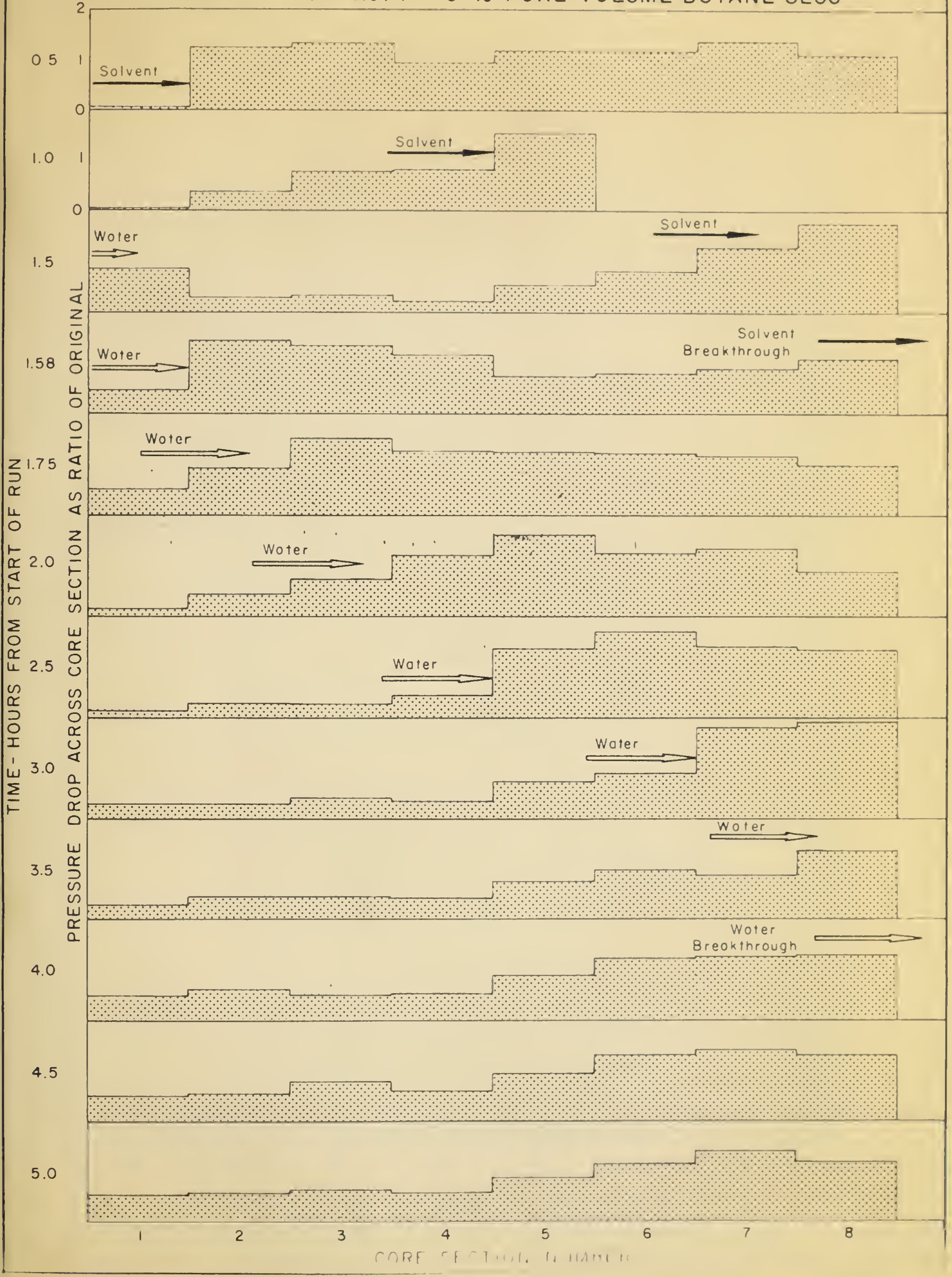


FIG. 3 RUN No. 4 - 6 % PORE VOLUME BUTANE SLUG



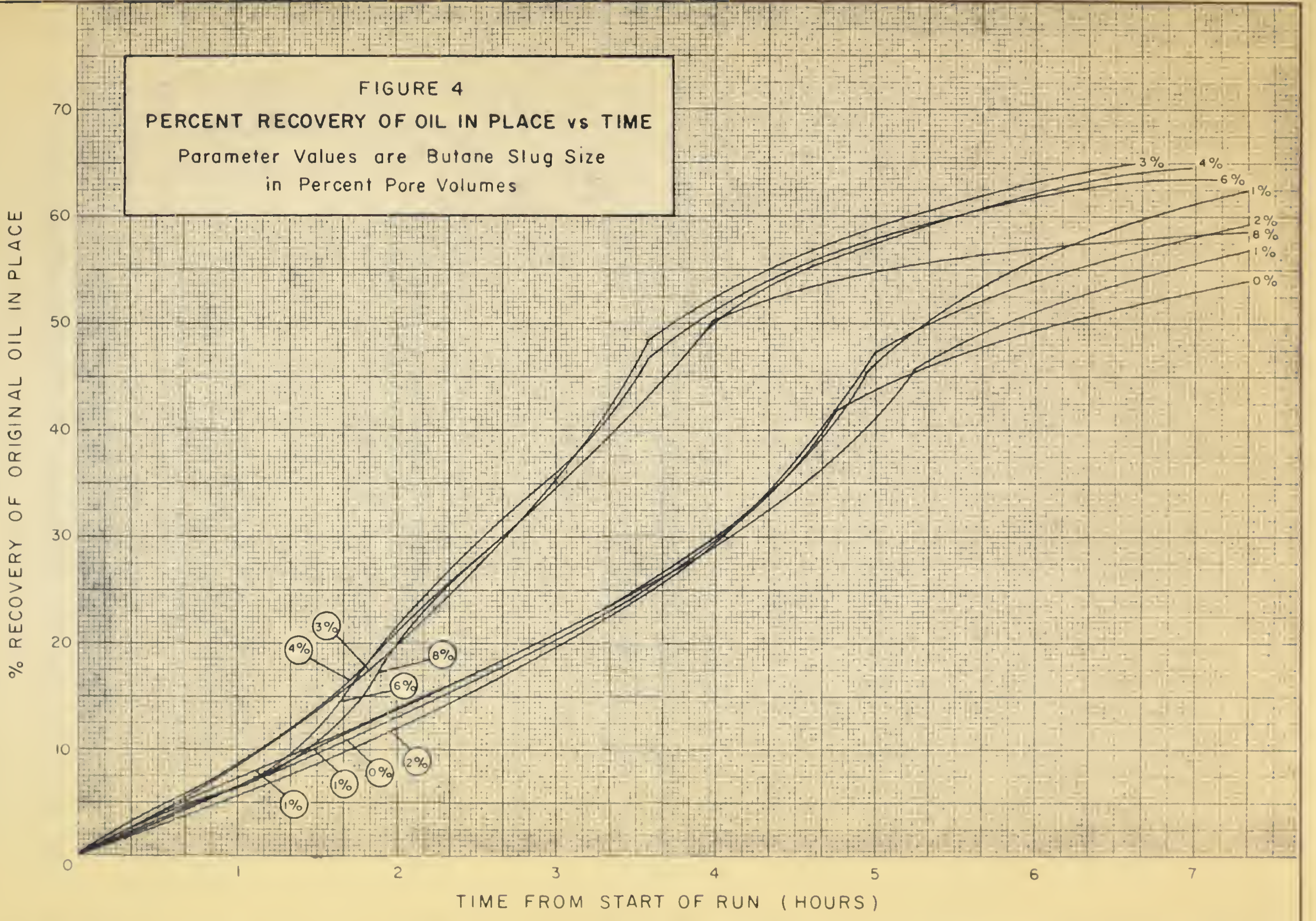


FIGURE 4

PERCENT RECOVERY OF OIL IN PLACE vs TIME

Parameter Values are Butane Slug Size
in Percent Pore Volumes

in the amount of solvent employed results in a major change in the time of breakthrough to water, identified by the sharp change in slope of the curve, the time of breakthrough for the 3, 4, 6 and 8% runs took, on the average, approximately three-quarters the time required by the 0, 1 and 2% runs. However, it is interesting to note that increasing the slug size above 3% did not result in any appreciable change in the time of breakthrough. A second significant feature of Figure 4, is the change in shape of the curves as the slug size is increased. The curves for the 0, 1 and 2% runs exhibit smooth curves, steadily increasing in slope until breakthrough. Similarly the 3% curve, although showing a substantially increased slope, still is a smooth curve of gradually increasing slope. However, above 3% a marked bulge in the curve is noted at recoveries in the order of 15 to 20%. Here again a critical slug size is noted. The significance of this critical size is best explained using pressure profile diagrams.

Figures 2 and 3 are presented here and discussed in an attempt to derive a logical explanation for the apparent change in mechanism at the critical slug size. Figure 2 is a pressure profile diagram of the waterflood run. The pressure drop in each section at various times is plotted as a ratio of the original single phase pressure drop. The arrows represent the estimated point of advance of the water flood front. The profile along the core is initially quite uniform and very close to unity. At time zero, of course, the profile is a straight

line at unit value. Although there is some evidence of anomalous behavious ahead of the flood front, it is well isolated and generally within the order of magnitude of the experimental error. As time progresses a zone of very low pressure drop advances into the core. This is due to the fact that the highly viscous oil has been displaced by the water phase of much lower viscosity. Despite the fact that the rate behind the flood front is equal to the rate ahead of the front and only slightly different from its value before passage of the interface, a vast change in profile occurs due primarily to'this difference in viscosity. Since the displacement mechanism is only about 42% efficient (as evidenced by breakthrough recovery) one would not expect the pressure drop immediately behind the flood front to drop to a value corresponding to that anticipated had the displacement been complete and water saturation behind the flood increased to unity. Rather the pressure drop behind the front should drop to a value somewhat greater than this, governed by the fractions of oil and water flowing and the relative permeability of the sand to each. This reasoning is substantiated by the profile in the section immediately behind the flood front. The water front is shown in the diagram to advance steadily across the core to breakthrough.

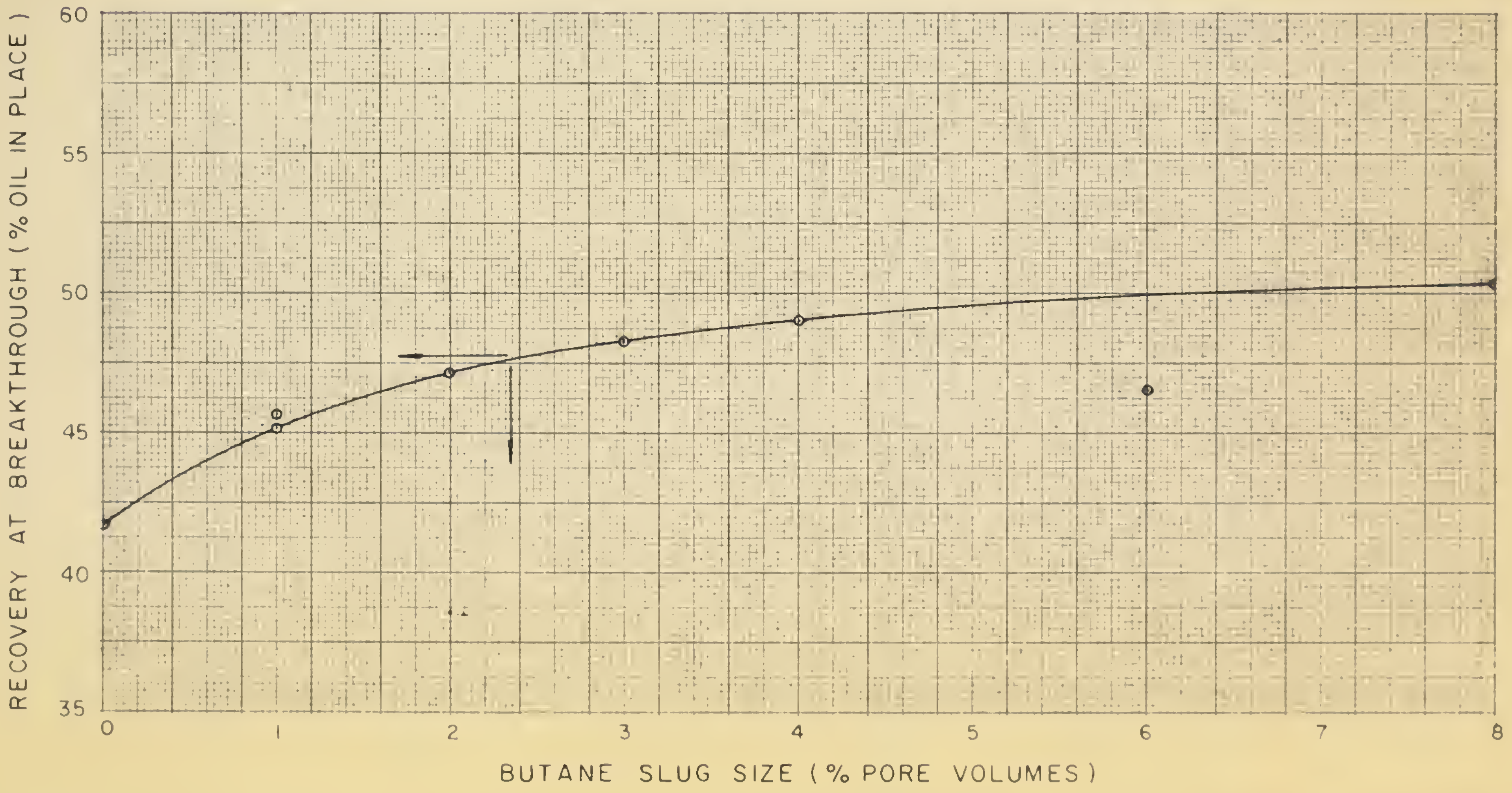
Figure 3 is the pressure profile diagram for the 6% butane slug run. The solid arrows indicate the estimated point of

advance of the solvent slug while the open arrows indicate the water front. The profile indicates quite readily that an entirely different mechanism than that exhibited by waterflood alone is governing this displacement. The rapid travel of the butane through the core is unmistakable, This is due to the very high mobility of the solvent. Because it is completely miscible with the oil, it has a relative permeability approaching unity, and with a very low viscosity (0.13 centipoises) there is very little resistance to "viscous fingering". Recoveries of oil at solvent breakthrough, as chosen from pressure profile considerations, were in the order of 20% of the oil in place. The subsequant water front, however, does not appear to be drastically affected by this fingering but maintains a pattern similar to that established by the waterflood run, although somewhat accelerated in configuration.

A similar mechanism is exhibited by the 1 and 2% butane runs (see profile diagrams Figure 5-A and 6-A appendix), although no butane breakthrough is apparent. It is reasonable to assume, then that at the low slug sizes, sufficient mixing has occurred to cause the butane to become dispersed and diluted with the oil phase such that it will lose its mobility and will not breakthrough. The net result of these small slugs has thus been merely to decrease the effective viscosity of the reservoir oil. This effect is more pronounced at the higher slug sizes and causes a temporarily increased production rate as the lower

FIGURE 5

PERCENT RECOVERY OF OIL IN PLACE
AT WATER BREAKTHROUGH
vs
BUTANE SLUG SIZE IN PERCENT PORE VOLUMES

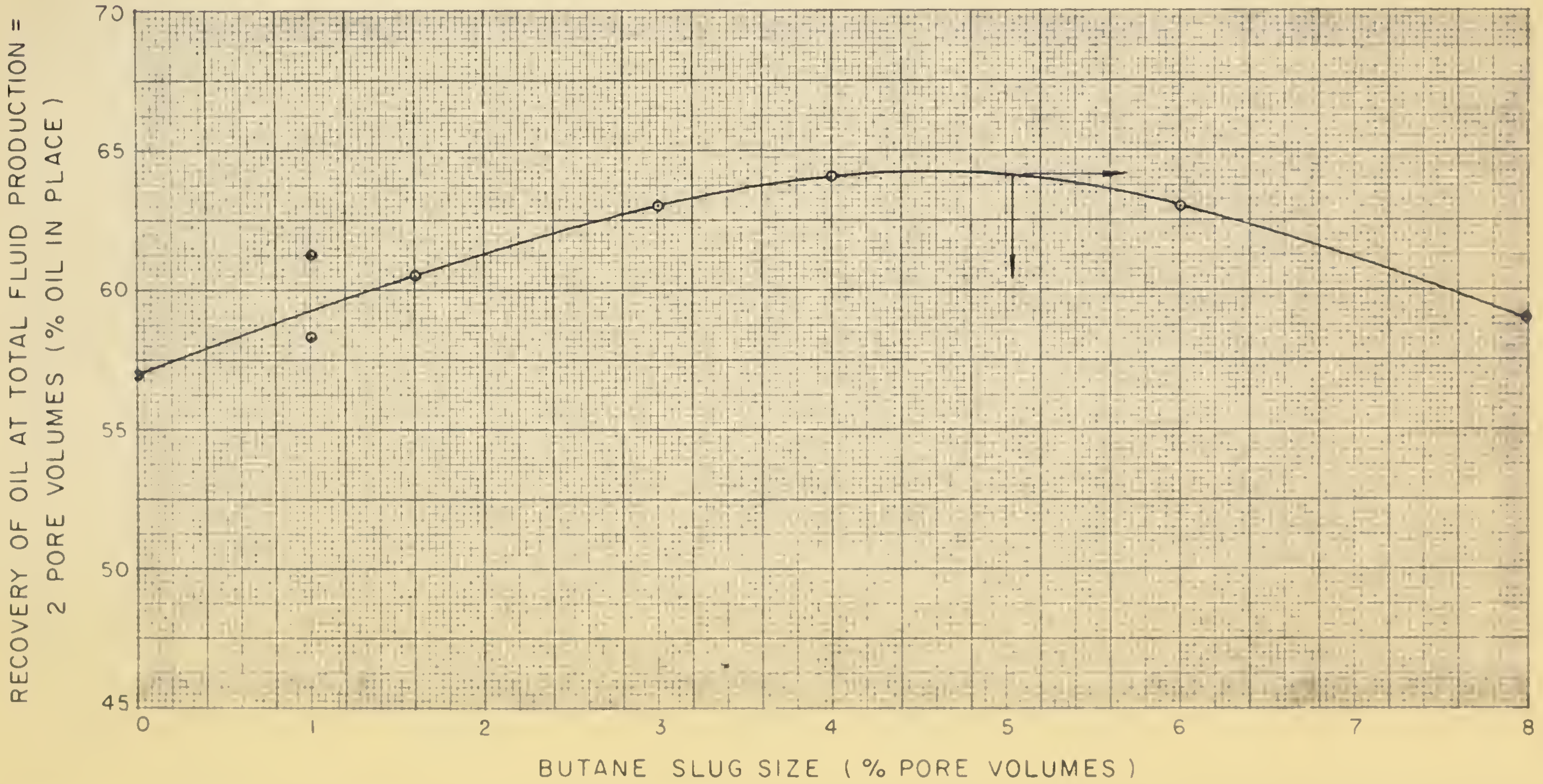


viscosity mixed zone is produced, giving rise to the temporary increase in rate detected in Figure 4. Thus, the use of very large slug sizes will result in a temporary breakthrough to almost pure solvent.

The 3% slug is the largest amount of solvent which will not cause the temporary increase in rate but will cause the greatly speeded time of breakthrough. It is probable, and this is substantiated by the pressure profile diagrams, that the 3% slug will provide enough solvent to substantially decrease the viscosity of the oil in place over the entire length of the core, but will not break through. However, since the mechanism of advance is by viscous fingering, larger quantities of solvent will not contact appreciably more oil but will flow along the low viscosity finger and actually break through. This low viscosity finger will also cause the speedup in production to breakthrough, since the experiments were carried out under constant pressure conditions and in this case rate is directly proportional to the "gross" viscosity of the system. Thus we would expect that increasing the slug size above 3% would not prove too effective in increasing recovery at breakthrough. Conversely, increasing solvent quantity between zero and 3% will be quite effective in increasing recovery since a proportionately larger amount of reservoir oil will be contacted with each increment.

The recovery at breakthrough curve, Figure 5, substantiates the above thinking. The curve shows a rapidly increasing trend with slug size increasing from 0 to 3% and then a levelling off,

FIGURE 6
PERCENT RECOVERY OF OIL IN PLACE
AT TOTAL FLUID PRODUCTION OF TWO PORE VOLUMES
VS
BUTANE SLUG SIZE IN PERCENT PORE VOLUMES



although a slightly increasing trend from 3 to 8% is noted. In consideration of this fact in conjunction with the vastly increased production rate illustrated by Figure 4, it is obvious that there is a critical slug size and that this slug size is 3% pore volume under this set of conditions . Also worthy of note is the excellent agreement of the duplicate 1% runs at breakthrough.

Figure 6 gives total recoveries for each run. This is the oil recovered as percent original oil in place at a total fluid production equal to 2 pore volumes. The curve does not show a trend similar to that exhibited by the recovery at breakthrough, Figure 5. Referring back to Figure 4, the very wide spread in the recovery versus time curves for the post-breakthrough period is noted. The slope of this portion of the curve is indicative of the efficiency of stripping of the water in the post-breakthrough period, and possess no obvious relationship with any of the factors involved. This lack of consistency in the recovery data after breakthrough is the reason why the total recovery does not show a correlation similar to that of breakthrough recovery. A best-fit curve of the total recovery data has been presented but the writer doubts if this curve could be reproduced if these or similar runs were repeated. The total recovery for the duplicate 1% runs, showing a discrepancy of 3% of the oil in place, further attests to this random behaviour in the final stages. This behaviour is common in waterfloods not conducted at constant rate.

SUMMARY AND CONCLUSIONS

It must be concluded from the experimental results that the equipment designed for and used in this research project has been proven to be adequate for the purpose for which it was designed. Reproducibility of results, at least up until the breakthrough point, has been shown to be quite good. Waterflood recoveries calculated using relative permeability and viscosity ratio principles substantiated the experimental results very closely. No acceptable method of calculating recoveries has yet been established for a miscible phase displacement, however, there is no reason to doubt the experimental results yielded by this project.

Pressure profile diagrams, previously lacking on miscible phase projects, have shown that mobility ratio is probably the most important single factor in controlling recovery at breakthrough of both miscible and immiscible liquid-liquid displacement processes. Profile diagrams indicate that the mechanism of frontal advance is by viscous fingering rather than the piston-like displacement predicted by many investigators, at least in cases where a very adverse mobility ratio exists. This is evidenced by the rapid breakthrough to solvent on the large slug size runs. In this way these results agree with those of Cole et al[5], Blackwell et al[2] and of Offeringa and Van der Poel[15] all of whom found that viscous

fingering predominated in cases of adverse mobility ratios. It is possible, then, that in some cases water as a secondary phase will be more efficient than gas. Even in cases where control is maintained such that the secondary gas phase is kept miscible with the solvent, the severely adverse viscosity ratio will undoubtedly result in channeling and viscous fingering even though virtually complete recovery of oil contacted is achieved. Conversely, if a solvent bank can be maintained between the water and the oil, benefits from both displacement mechanisms may be obtained. A combination of the high displacement efficiencies of the miscible phase and the reasonably good areal sweepout of a waterflood should result in very high recoveries where the viscosity ratio is not too adverse. However, this process does possess the disadvantage of lack of control of slug size since it cannot be added to as can, say, the solvent bank in a condensing gas drive type mechanism.

It must be concluded that for a displacement carried out under conditions similar to this project there is a definite "critical" slug size. Above this critical size decreased time of breakthrough and increased recoveries are experienced. Below the critical size breakthrough times are fairly constant at a level well below that of the above critical slugs. In this region, too, breakthrough recovery increases rapidly with slug quantity up to the critical and

shows only slight increase thereafter. These changes are considered to be due almost entirely to dilution effects causing a change in the effective viscosity of the in place oil. The recovery at breakthrough curve (Figure 5) would probably show the same configuration but be greatly exaggerated if a reservoir oil of appreciably lower viscosity were displaced.

The theory of piston-like displacement of oil cannot be accepted for mobility ratios of this magnitude; rather the mechanism of advance is by viscous fingering.

The recovery of oil after breakthrough is not uniform and cannot be predicted for a constant pressure displacement.

Restating the Conclusions:

1. The equipment yielded reliable and accurate results.
2. Viscosity ratio and relative permeability are major factors governing time and recovery at breakthrough.
3. Water as a secondary phase will probably yield higher breakthrough recoveries in cases where mobility ratio is a serious problem.
4. Increased production to breakthrough and decreased time of payout of capital expenditure may make this type of project economically attractive although lack of control of the size of the L.P.G. slug subsequent to injection may be a serious problem.
5. For the conditions employed in this investigation there was an

optimum slug size; 3% pore volume.

6. Increased recoveries and decreased time of breakthrough was caused primarily by the fingering through of the solvent and resulting dilution and viscosity reduction of the oil.
7. Recovery of oil after breakthrough was not predictable and shows no obvious correlation with related factors.

Recommendations

The prediction of the performance of a miscible phase displacement would be of tremendous importance in reservoir engineering. Before such a system can be devised, the influence which each variable has upon that performance must be thoroughly evaluated, by research. This project has investigated the mechanism of displacement for very adverse mobility ratio processes. Further work on this mechanism and other factors such as gravitational effects, scaling rules, diffusion coefficients, type of media, etc., is required before a thorough knowledge of the process is acquired. With this in mind, it is recommended that:

1. a complete research program be continued to identify and evaluate the effect of the variables involved in a miscible phase displacement.
2. as knowledge of this process is acquired, a continuing attempt be made to correlate the data and predict the performance of a miscible phase displacement.

BIBLIOGRAPHY

1. Aronofsky, J.S., and Heller, J.P., "A Diffusion Model to Explain Mixing of Flowing Miscible Fluids in Porous Media", Trans. AIME, Vol. 210, P. 345 (1957).

2. Blackwell, R.J., Rayne, J.R., and Terry, W.M., "Factors Influencing the Efficiency of Miscible Displacement", Trans. AIME Vol. 217, P. 1 (1959).

3. Brigham, W.E., Reed, P.W., and Dew, J.N., "Experiments on Mixing by Fluid Flow in Porous Media", Presented at the AIChE - SPE Joint Symposium on Fundamental Concepts of Miscible Fluid Displacement: Part II - 52nd annual meeting, San Francisco, December 6 - 9, 1959.

4. Buckley, S.E., and Leverett, M.C., "Mechanism of Fluid Displacement in Sands", Trans. AIME Vol. 146, P. 107 (1942).

5. Cole, F.W., Cowan, J.V., and Jackson, M.L., "Miscible Displacement Studies Using Radial Cores", Presented at the AIChE - SPE Joint Symposium on Fundamental Concepts of Miscible Fluid Displacement: Part II - 52nd annual meeting, San Francisco, December 6 - 9, 1959.

6. Connally, C.A., and Mason, W.L., "Analysis of Performance of Pembina Pilot LPG Flood", Paper 1308-G presented at the 34th annual fall meeting of the SPE of AIME, Dallas, Texas, October 4, 1959.

7. Caudle, B.H., and Dyes, A.B., "Improving Miscible Displacement by Gas-Water Injection", Trans. AIME Vol. 213, P. 281 (1958).

8. Everett, J.P., Gooch, F.W., Jr., and Calhoun, J.C., Jr., "Liquid - Liquid Displacement in Porous Media as Effected by Liquid - Liquid Viscosity Ratio and Liquid - Liquid Miscibility", Trans. AIME Vol. 189, P. 215 (1950).

9. Hall, H.N., and Geffen, T.M., "A Laboratory Study of Solvent Flooding", Trans. AIME Vol. 210, P. 48 (1957).

10. Handy, L.L., "An Evaluation of Diffusion Effects in Miscible Liquid Displacement", J. Pet. Tech. Vol. 11, P. 61 (1959).

11. Henderson, J.H., Gove, N.B., Ledbetter, H.J., and Griffith, J.D., "A Laboratory Investigation of Oil Displacement from Porous Media by a Liquid Petroleum Gas", Trans. AIME Vol. 198, P. 33 (1953).

12. Justen, J.J., Hoenmans, P.J., and Groeneveld, H., "Field Results of the Pembina Miscible Displacement Pilot", Paper 1307-G presented at the 34th annual fall meeting of the SPE of the AIME, Oct. 4, 1959.

13. Koch, H.A., Jr., and Slobod, R.L., "Miscible Slug Process", Vol. 210, P. 40 Trans. AIME (1957).

14. Lacey, J.W., Draper, A.L., and Binder, G.G., "Miscible Fluid Displacement in Porous Media", Trans. AIME Vol. 213, P. 76 (1958).

15. Offeringa, J., and van der Poel, C., "Displacement of Oil from Porous Media by Miscible Liquids", Trans. AIME Vol. 201, P. 310 (1954).

16. Round, G.F., "A Review of Miscible Flooding Mechanisms", Report to the Research Council of Alberta, Edmonton, Alberta (1959).

17. Stone, H.L., and Crump, J.S., "The Effect of Gas Composition upon Oil Recovery by Gas Drive", Trans. AIME Vol. 207, P. 105 (1956).

18. Whorton, L.P., and Kieschnick, W.F., Jr., "A Preliminary Report on Oil Recovery by High Pressure Gas Injection", API Drilling and Production Practice, P. 247 (1950).

APPENDIX

I - Correction of Oil Production for Butane in Solution

Using the vapor pressure curve of butane and of a typical high molecular weight oil assumed to be similar to 'Primol "D" ', a convergence pressure was estimated for the system as being 1,000 psia. At 120°F and atmospheric pressure (measuring cylinder conditions) K isobutane is 6.2 and K normal butane is 4.6. The weighted average equilibrium ratio is thus 4.9 since the butane used was approximately 79% normal butane and the remainder isobutane. The amount of butane remaining in the oil as a liquid would then be $\frac{5.9 - 4.9}{5.9} = 0.17$ expressed as a mole fraction of the total.

Judgement dictated that this figure be upgraded somewhat since it was felt that very little butane was flashing out of the oil upon pressure reduction possibly because the effluent took quite some time to reach equilibrium conditions and also it was desired to present a fairly conservative estimate of the advantages of using solvent. With this in mind it has been assumed that 25% of the butane used remained in solution in the oil at the time of measurement. Oil volumes were reduced accordingly between 20% recovery, (average butane breakthrough) and water breakthrough in proportion to the amount of production. At water breakthrough all butane was assumed to have been produced and volumes between this value and total recovery were reduced a uniform amount (25% x Slug Size).

II - Calculation of Recovery at Breakthrough for a Linear Waterflood

Buckley and Leverett[4] have shown that residual water saturation at breakthrough can be predicted quite accurately based on the following assumptions:

(a) Oil is moving behind the flood front

(b) The relative movement of oil and water behind the flood front is given by relative permeability data

(c) No water moves ahead of the flood front.

They have also shown that when gravity effects and capilliary forces are ignored the fraction of water flowing behind the flood front may be expressed by their well known Fractional Flow Formula:

$$fw = \frac{1}{1 + \frac{koM_w}{kwM_o}} \quad * \qquad (1)$$

They further state that the distance which a given saturation value moves behind the flood front may be expressed by:

$$(\Delta x)_{Swx} = \frac{Qt}{\phi A} \frac{(dfw)}{(dSw)_{Swx}} \qquad (2)$$

After a given amount of water injection has occurred the saturation Swx will have travelled a distance Δx. At distances less than Δx, saturations greater than Swx will exist. If saturation

---

* Nomenclature is at the end of this section

is plotted versus distance the area under the curve will be equal to $\frac{Qt}{\phi A}$ or:

$$Area = \frac{Qt}{\phi A} = Swx\,(\Delta x)_{Swx} + \int_{Swx}^{1.0} \Delta x \, dSwx \qquad (3)$$

Substituting equation (2) into equation (3) yields:

$$\frac{Qt}{\phi A} = Swx \, \frac{Qt}{\phi A} \left(\frac{dfw}{dSw}\right)_{Swx} + \int_{Swx}^{1.0} \frac{Qt}{\phi A} \left(\frac{dfw}{dSw}\right)_{Swx} dSwx \qquad (4)$$

Equation (4) reduces to:

$$(fw)_{Swx} = Swx \;(dfw/dSw)_{Swx} \qquad (5)$$

By differentiating equation (1) with respect to Sw and combining with equation (5), the effect of relative permeability as well as viscosity ratio may be expressed:

$$\frac{dfw}{dSw} \doteq - \frac{(fw)^2 \; Mw/Mo \;\; d\,(ko/kw)}{dSw} \qquad (6)$$

Substituting equation (1) and equation (6) into equation (5) and simplifying we obtain:

$$Mo/Mw + (ko/kw)_{Swx} = S_{wx} \left[d\; ko/kw \;/\; dSw \right]_{Swx} \qquad (7)$$

Looking again at equation (2) and restating for breakthrough conditions ($\Delta x = L$):

$$L = \frac{Qt}{\phi A} \left(dfw/dSw \right)_{Swx} \qquad (8)$$

It is also obvious that the percent recovery at breakthrough is:

$$\%\ Recovery\ at\ Breakthrough = \frac{Qt}{\phi A L}\,(100)$$

$$= \frac{100}{(dfw/dSw)_{Sw_L}}$$

$$= 100 \frac{Sw_L}{(fw)_{Sw_L}} \qquad (9)$$

Now using the relative permeability curve for a typical unconsolidated sand (Figure 1-A) a relative permeability versus water saturation curve (ko/kw vs. Sw) may be drawn. The slope of this curve at a given point may then be determined graphically and multiplied by the water saturation at that point to yield a factor $\left\{ Sw \frac{d\, ko/kw}{dSw} \right\}$ which is then plotted versus water saturation. These latter two curves are presented in Figure 2-A.

Now by choosing a value of water saturation, Sw, values of (ko/kw) and $Sw \left(\frac{d\, ko/kw}{(dSw)} \right)$ may be determined graphically and used directly in equation (7) to yield a viscosity ratio, M_o/M_w. This value along with the relative permeability ratio is now substituted into the fractional flow formula (equation (1)) to give a value of fw. From this value of fw and the value of Sw for which it was chosen a recovery at breakthrough may be calculated using equation (9).

The above procedure is followed for a number of values of water saturation and the calculated breakthrough recoveries plotted versus the viscosity ratio yielded by solving equation (7). This was done for the core used in this project and

the resulting calculated curve appears in Figure 3-A. This final plot shows that for the viscosity ratio in question, 72.6, a recovery of 43.2% of the oil in place is to be expected. It must be remembered, however, that this is based on a typical relative permeability curve.

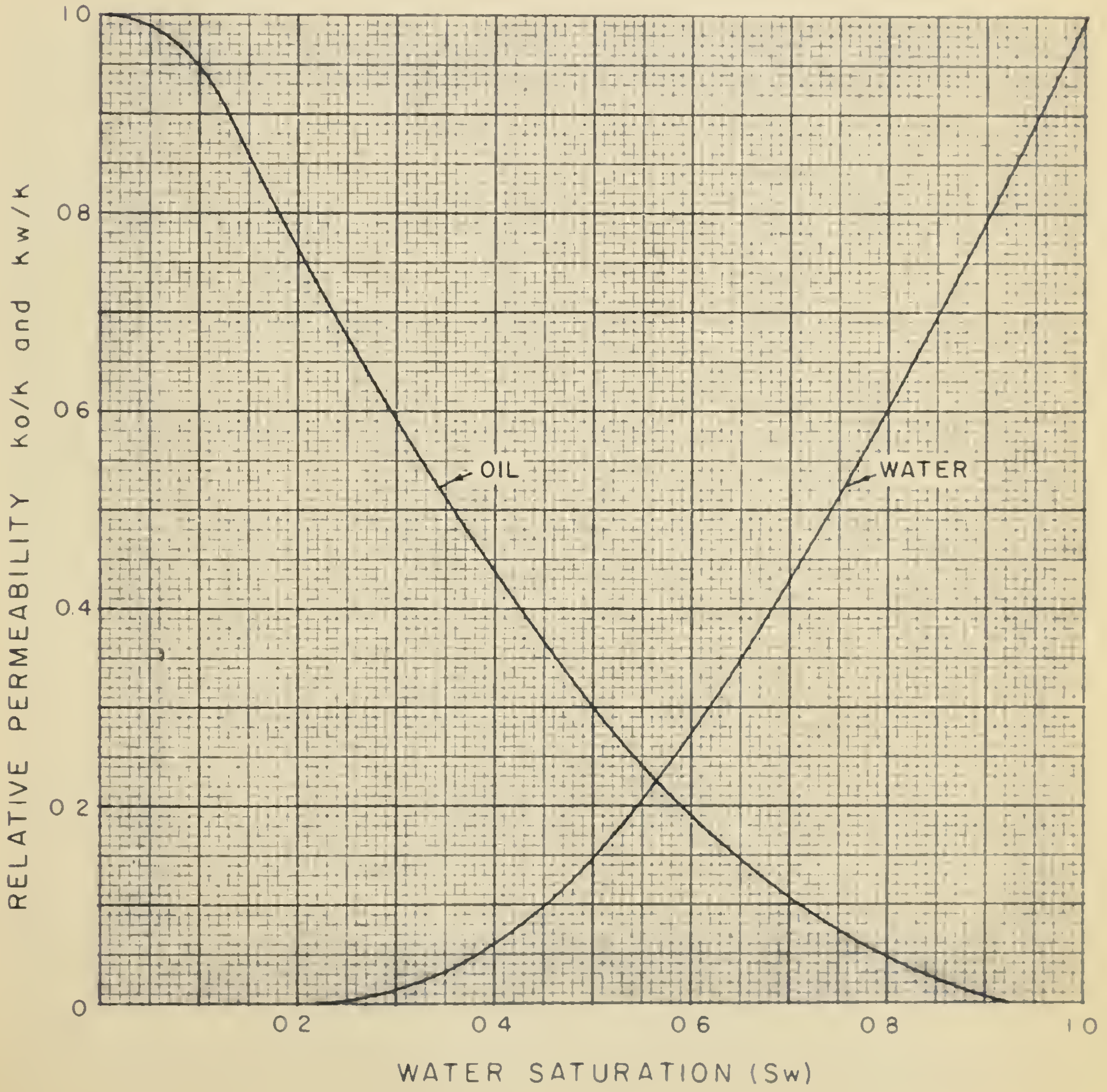
NOMENCLATURE

A	cross-sectional area
F_w	fraction of water flowing behind flood front at any given point
ϕ	fractional porosity
k_o	relative permeability to oil
k_w	relative permeability to water
L	total length of linear system
M_o	viscosity of oil
M_w	viscosity of water
Qt	cumulative water injected to move a given saturation a distance Δx
Swx	water saturation at flood front
x	distance in direction of travel of flood

FIGURE I-A

TYPICAL RELATIVE PERMEABILITY CURVE FOR UNCONSOLIDATED SAND

(After Buckley and Leverett - AIME 1942)



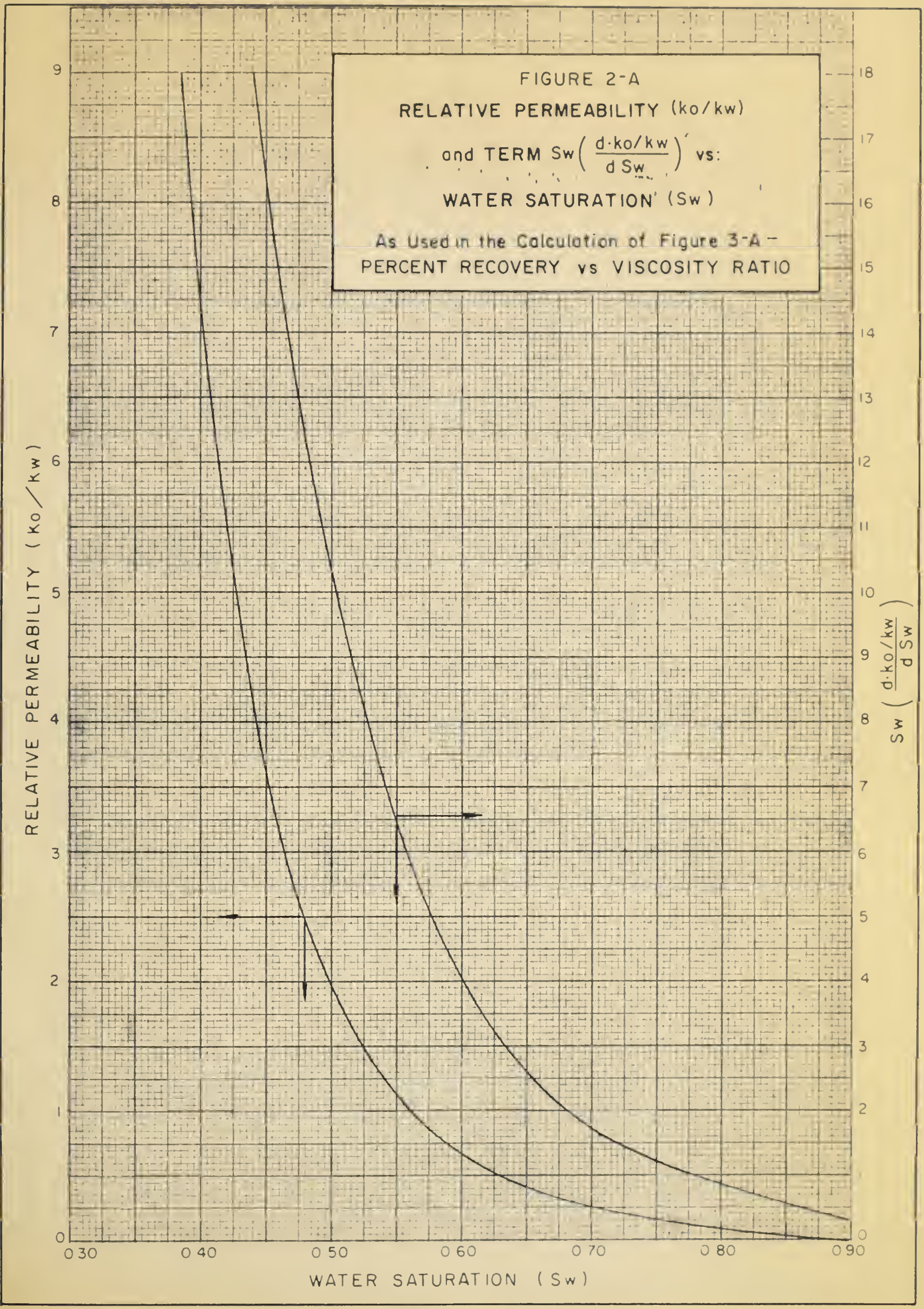


FIGURE 2-A

RELATIVE PERMEABILITY (ko/kw) and TERM $Sw\left(\frac{d\cdot ko/kw}{d\,Sw}\right)$ vs: WATER SATURATION (Sw)

As Used in the Calculation of Figure 3-A – PERCENT RECOVERY vs VISCOSITY RATIO

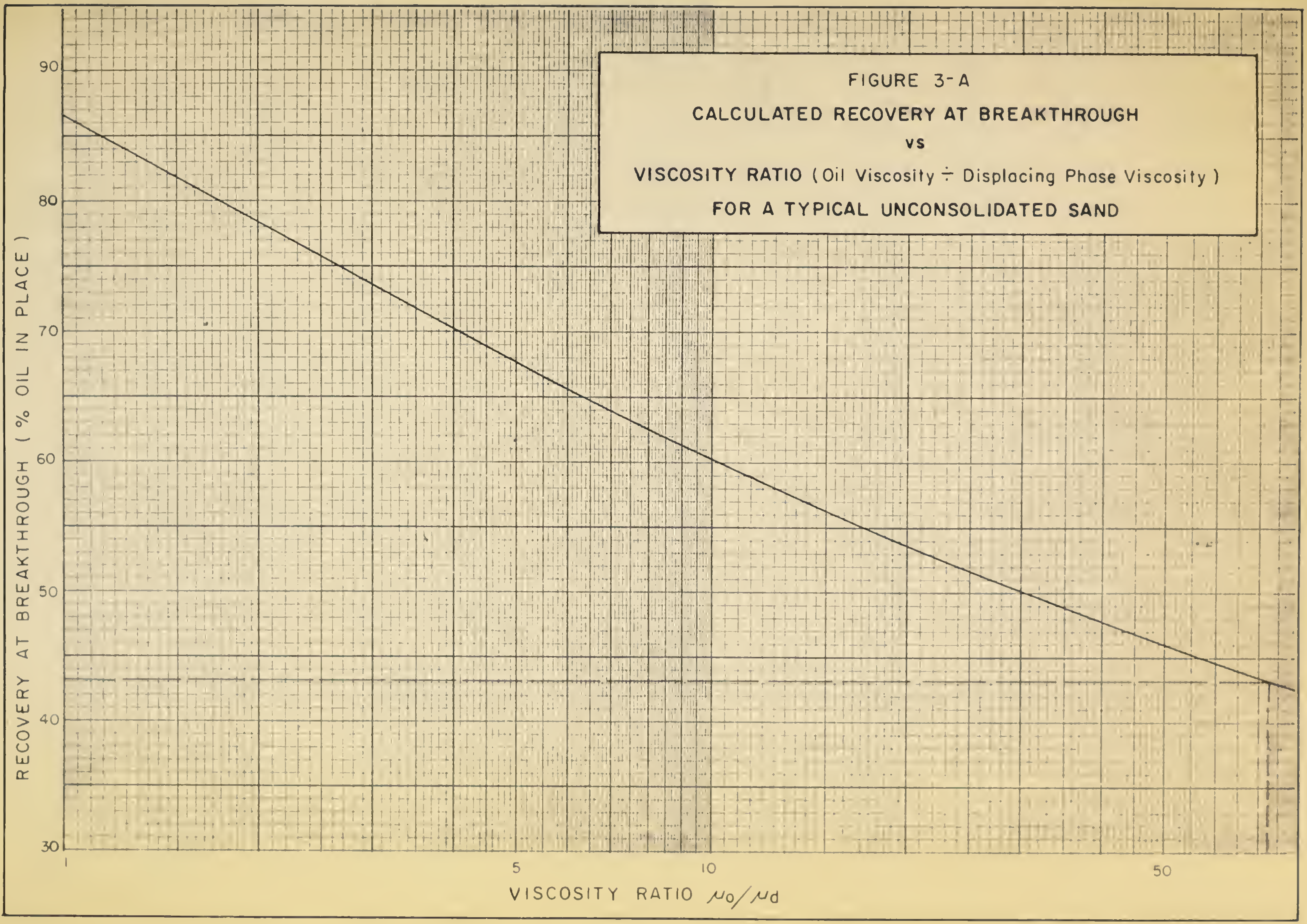


FIGURE 3-A

CALCULATED RECOVERY AT BREAKTHROUGH

vs

VISCOSITY RATIO (Oil Viscosity ÷ Displacing Phase Viscosity)

FOR A TYPICAL UNCONSOLIDATED SAND

FIG. 4-A RUN No. 9 - WATERFLOOD

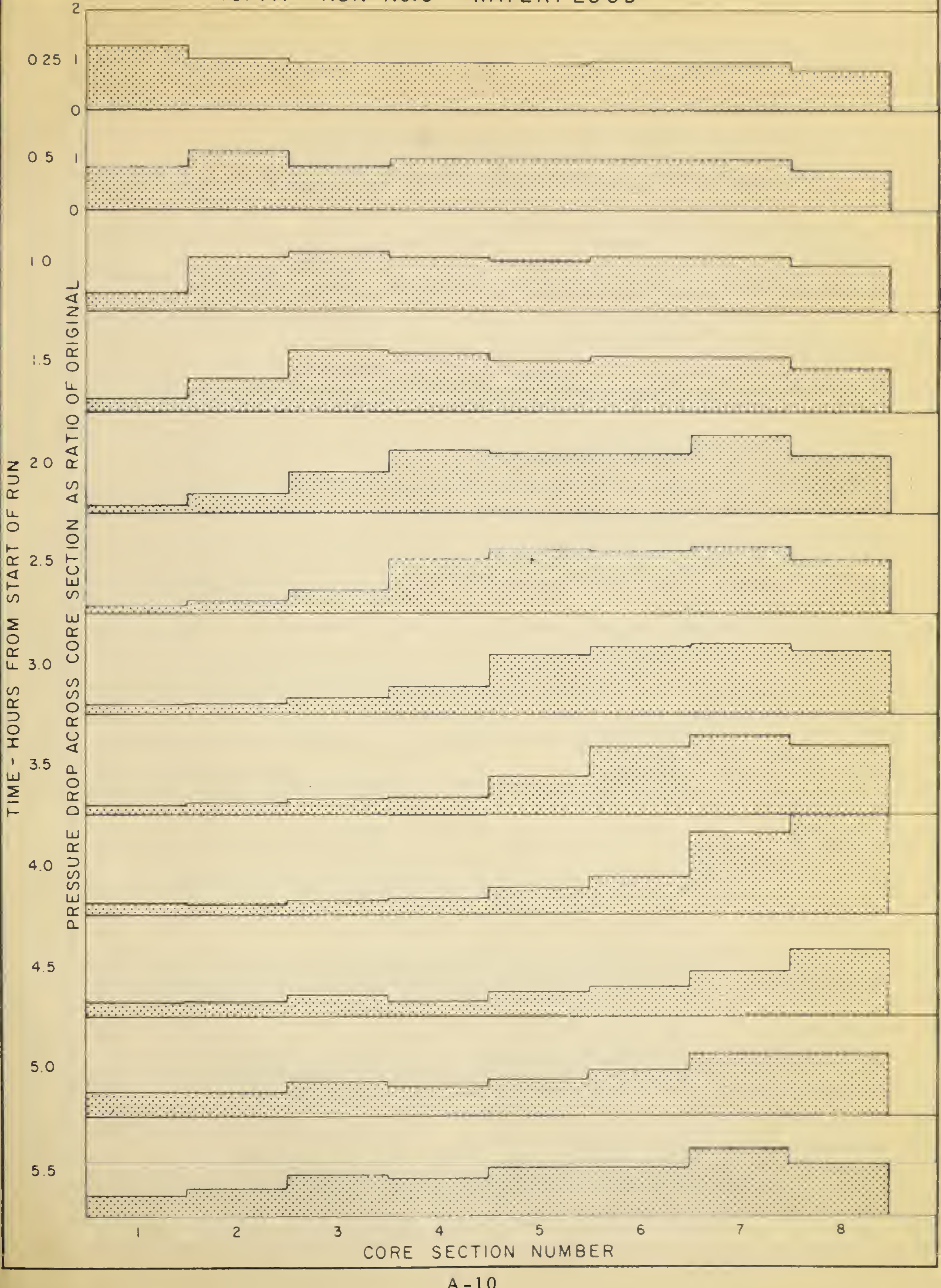


FIG. 5-A RUN No. 2 - 1% PORE VOLUME BUTANE SLUG

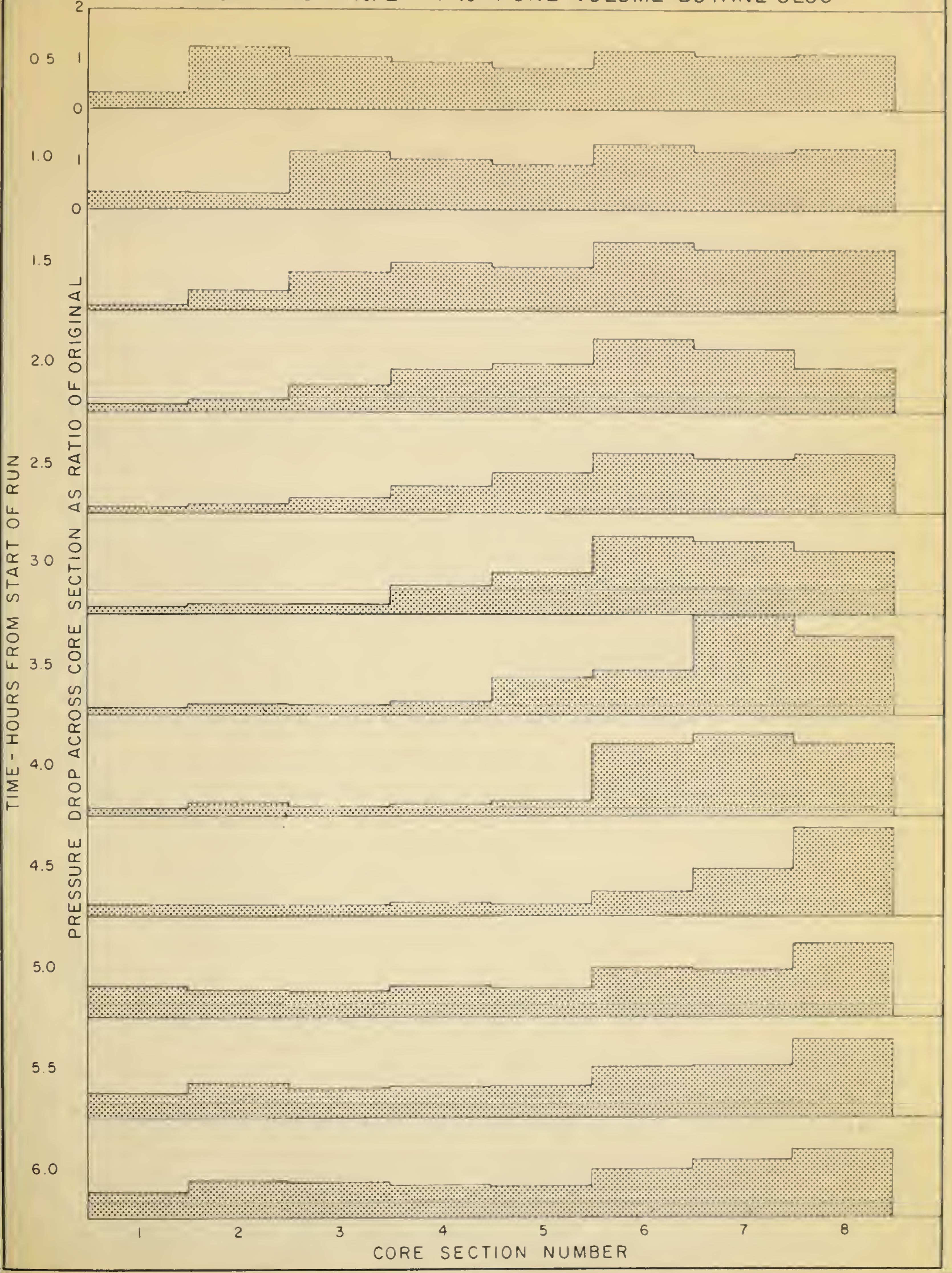


FIG. 6-A RUN No. 8 - 1% PORE VOLUME BUTANE SLUG

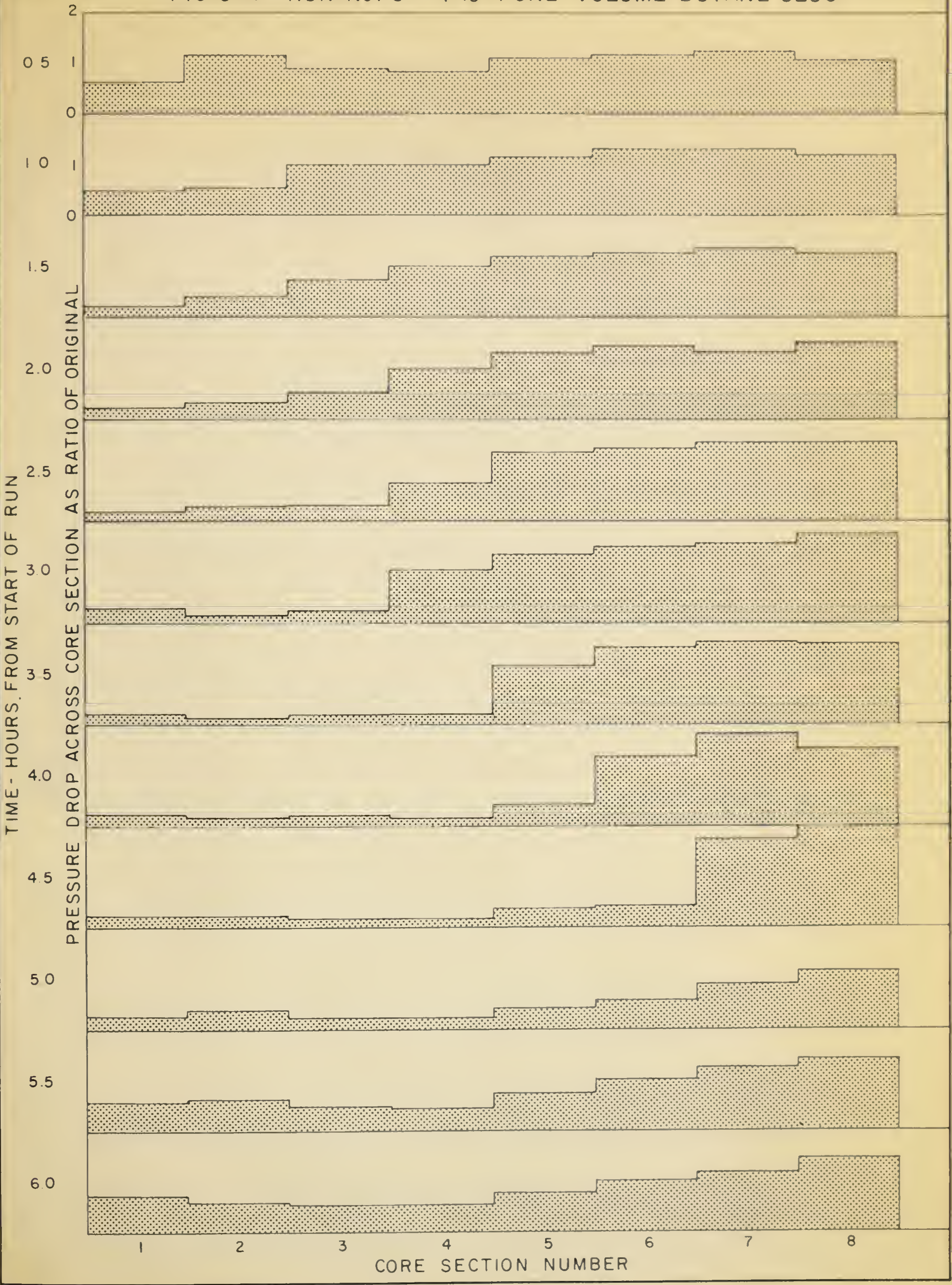


FIG. 7-A RUN No. 10 - 2 % PORE VOLUME BUTANE SLUG

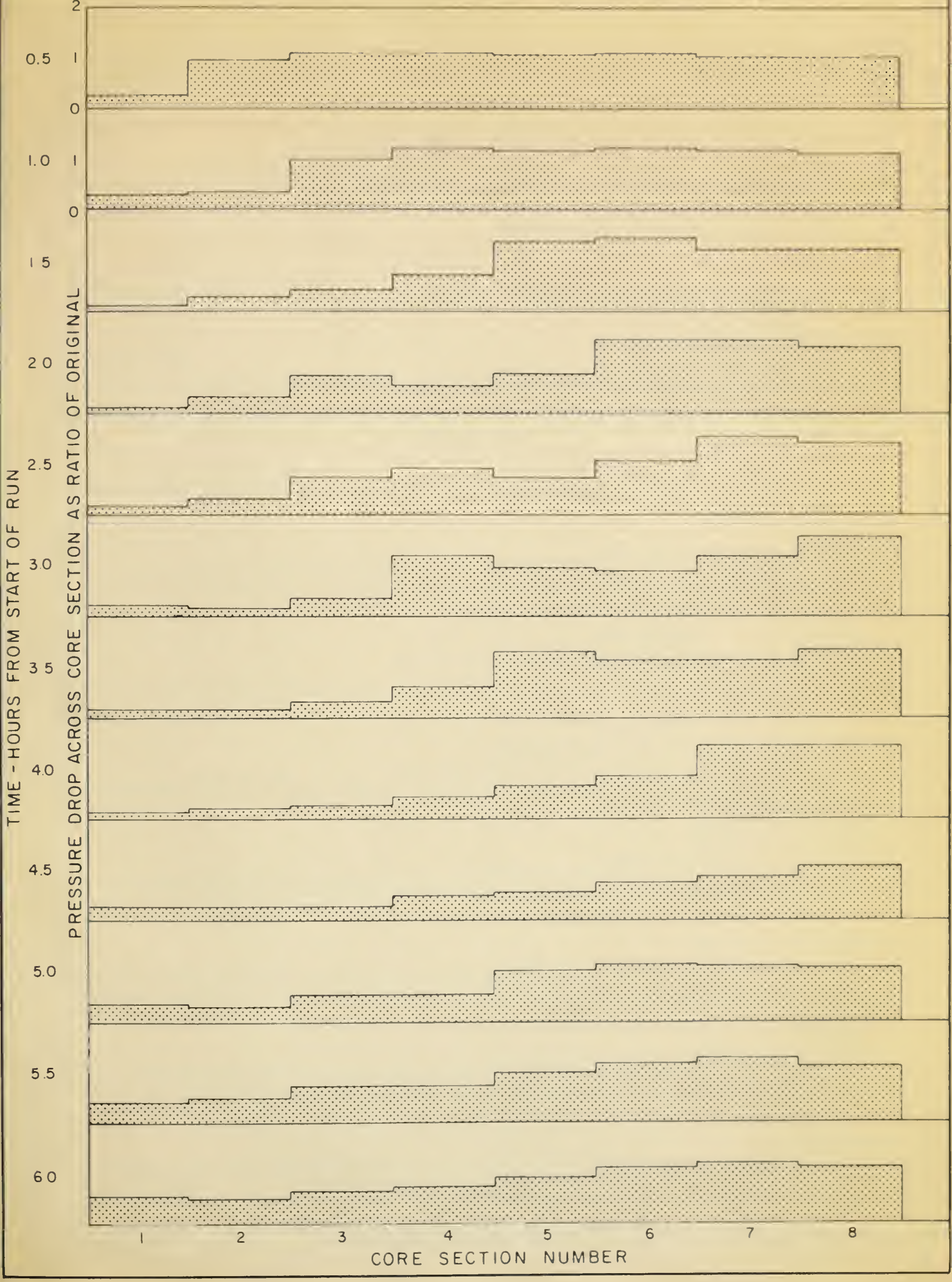


FIG. 8-A RUN No. 6 - 3 % PORE VOLUME BUTANE SLUG

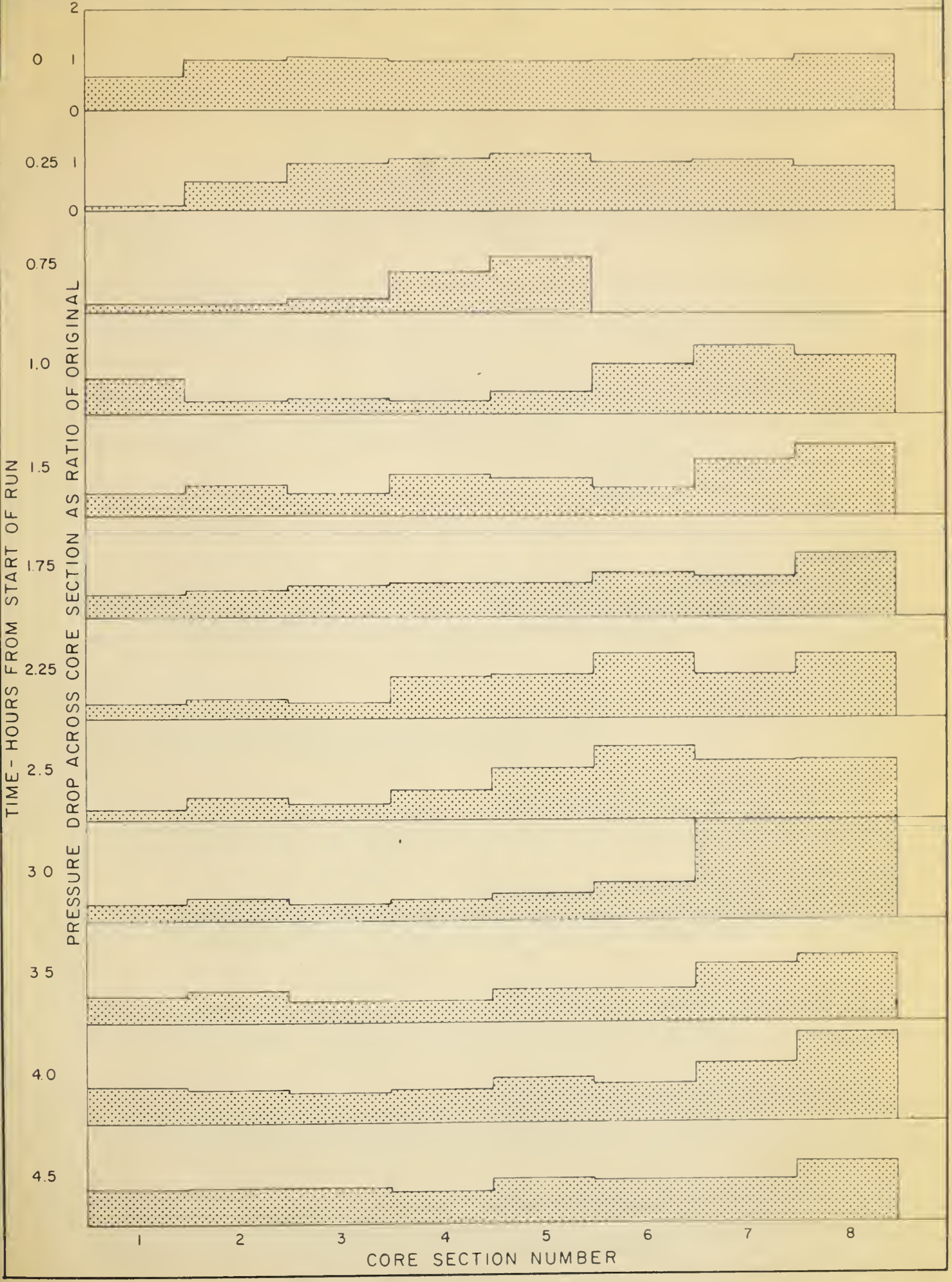


FIG. 9-A RUN No. 3 - 4 % PORE VOLUME BUTANE SLUG

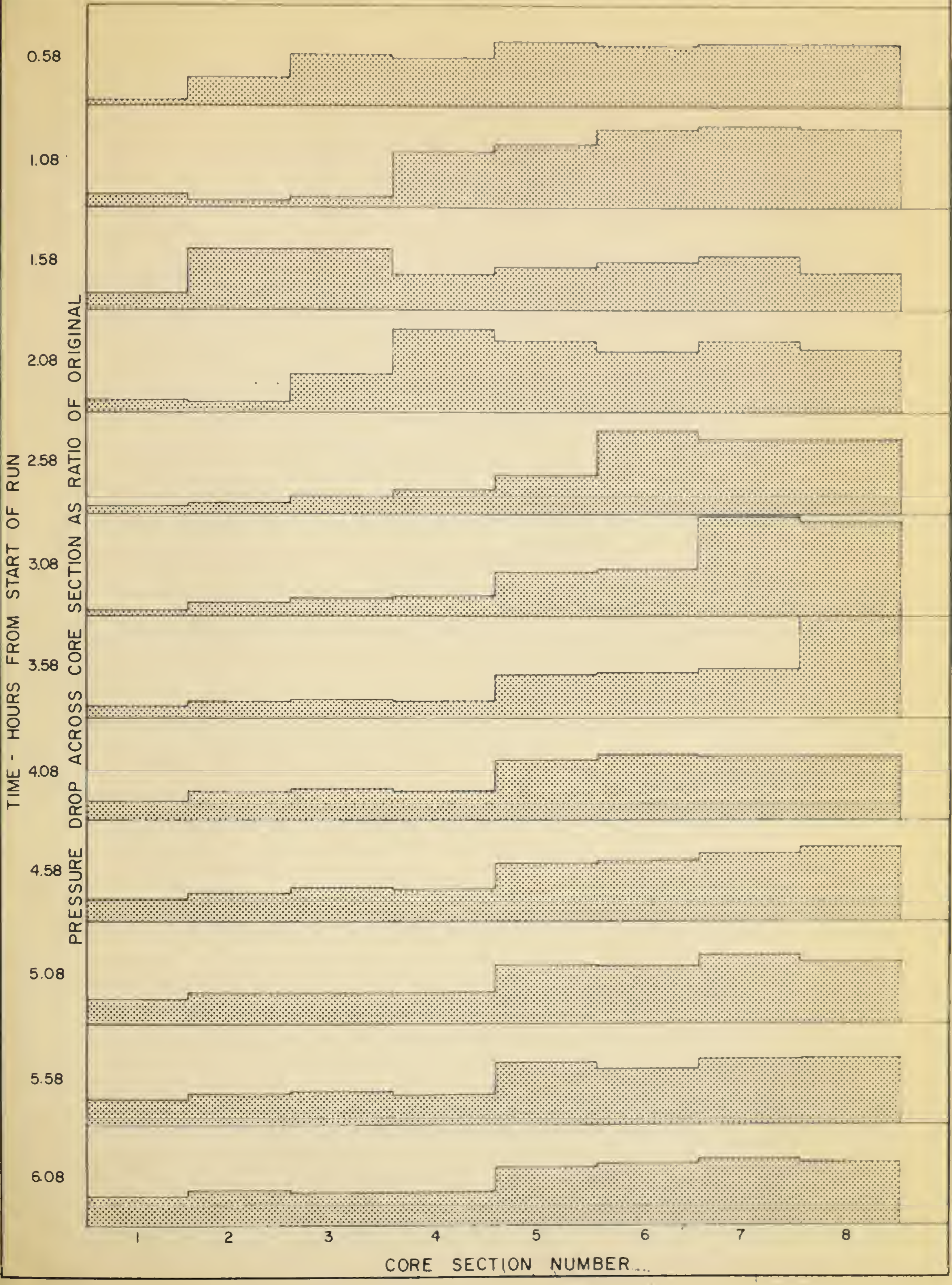


FIG. 10-A RUN No. 4 - 6 % PORE VOLUME BUTANE SLUG

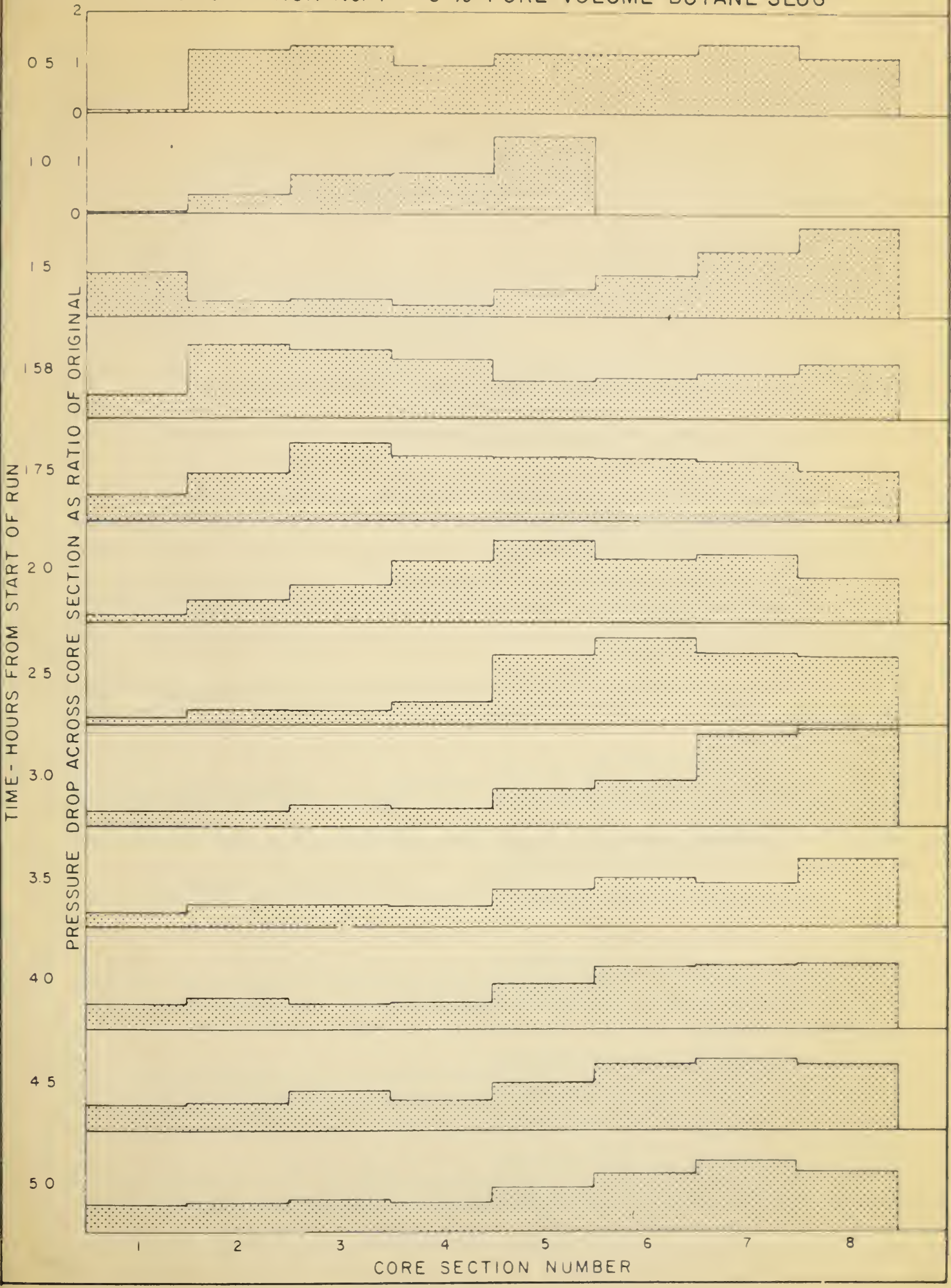


FIG. 11-A RUN No. 5 - 8 % PORE VOLUME BUTANE SLUG

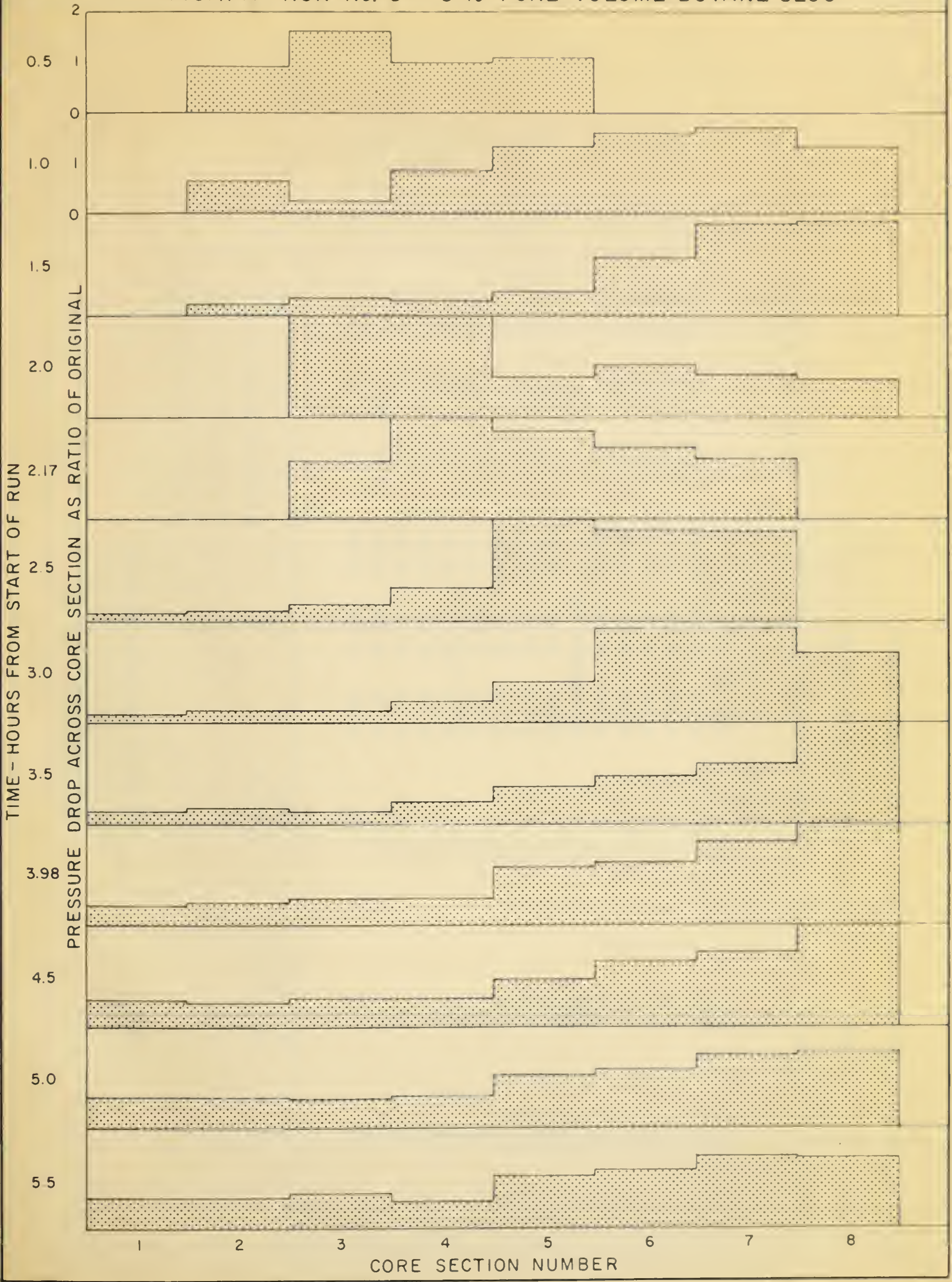


TABLE 1-A

RECORDED DATA

Run No. 2 Slug Size: 1% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section 1	2	3	4	5	6	7	8	9
0.5	28	28	3.6	0.36	1.28	1.06	0.95	0.82	1.19	1.10	1.18	
1.0	54	54	7.0	0.38	0.33	1.21	1.05	0.93	1.32	1.19	1.29	
1.5	76	76	9.8	0.15	0.43	0.79	0.99	0.90	1.36	1.27	1.27	
2.0	105	105	13.6	0.15	0.26	0.55	0.87	0.97	1.48	1.28	0.90	
2.5	134	134	17.4	0.13	0.19	0.31	0.56	0.83	1.21	1.10	1.20	
3.0	163	163	21.1	0.15	0.20	0.23	0.59	0.84	1.57	1.47	1.27	
3.5	194	194	25.1	0.12	0.21	0.21	0.30	0.74	0.91	2.01	1.57	
4.0	233	232	30.1	0.16	0.25	0.19	0.26	0.33	1.45	1.62	1.46	
4.5	280	279	36.1	0.25	0.28	0.23	0.29	0.27	0.51	0.96	1.79	
4.92	350	348	45.1	Breakthrough								
5.0	355	353	45.7	0.62	0.58	0.56	0.64	0.61	1.00	0.96	1.49	
5.5	408	406	52.6	0.51	0.71	0.60	0.62	0.64	1.03	1.04	1.57	
6.0	430	428	55.4	0.52	0.75	0.76	0.66	0.67	0.99	1.15	1.37	
6.5	455	453	58.7	0.63	0.75	0.77	0.68	0.66	1.00	1.11	1.26	
7.0	475	473	61.3	0.65	0.74	0.83	0.68	0.65	0.99	1.06	1.30	
7.5	505	503	65.1	End of run								

Oil in Place = 772 cc = 96.6% Pore Volume - Connate Water = 272 cc = 3.4% Pore Volume

Breakthrough Recovery (corrected) = 348 cc's = 45.1% Oil in Place

Total Recovery (corrected) = 503 cc's = 65.1% Oil in Place

TABLE 2-A

RECORDED DATA

Run No. 3 Slug Size: 4% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section								
				1	2	3	4	5	6	7	8	9
0.58	35	35	5.0	0.11	0.56	1.02	0.96	1.25	1.20	1.22	1.24	1.61
1.08	62	62	8.8	0.26	0.12	0.21	1.09	1.24	1.53	1.60	1.54	1.44
1.58	103	103	14.7	0.31	1.19	1.18	0.69	0.82	0.95	1.05	0.71	2.21
2.08	155	155	22.1	0.22	0.18	0.75	1.61	1.37	1.17	1.37	1.22	1.33
2.58	205	203	28.9	0.17	0.23	0.35	0.47	0.74	1.63	1.46	1.46	2.20
3.08	255	251	35.8	0.17	0.27	0.35	0.36	0.84	0.90	1.90	1.84	1.99
3.58	310	304	43.3	0.24	0.32	0.37	0.33	0.82	0.89	0.93	2.16	2.41
3.92	350	342	48.7	Breakthrough								
4.08	375	367	52.3	0.35	0.56	0.60	0.54	1.14	1.27	1.25	1.23	2.05
4.58	395	387	55.1	0.42	0.56	0.66	0.63	1.11	1.17	1.33	1.44	1.73
5.08	415	407	58.0	0.48	0.60	0.60	0.60	1.13	1.10	1.33	1.19	1.99
5.58	432	424	60.4	0.50	0.62	0.65	0.57	1.21	1.08	1.27	1.31	1.87
6.08	445	437	62.3	0.57	0.70	0.65	0.65	1.12	1.21	1.29	1.23	1.73
6.58	458	450	64.1	0.61	0.66	0.75	0.68	1.05				
6.62				End of run								

Oil in Place = 702 cc = 75.6% Pore Volume, Connate Water = 14.4% = 117.4 cc's.

Breakthrough Recovery (corrected) = 342 cc's = 48.7% Oil in Place

Total Recovery (corrected) = 450 cc's = 64.1% Oil in Place

TABLE 3-A

RECORDED DATA

Run No. 4 Slug Size: 6% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section 1	2	3	4	5	6	7	8	9
0.5	21.8	21.8	2.8	0.06	1.24	1.32	0.95	1.19	1.20	1.39	1.13	1.02
1.0	48.5	48.5	6.3	0.02	0.39	0.79	0.86	1.56				
1.5	86.0	86.0	11.1	0.88	0.29	0.35	0.24	0.54	0.82	1.31	1.79	2.35
1.58	97	97	12.6	0.48	1.44	1.35	1.16	0.74	0.80	0.90	1.09	1.12
1.75	128	128	16.6	0.51	0.95	1.52	1.27	1.26	1.23	1.17	0.98	0.80
2.0	164	163	21.2	0.15	0.43	0.75	1.21	1.63	1.25	1.34	0.89	1.64
2.5	228	224	29.1	0.12	0.27	0.30	0.46	1.38	1.70	1.41	1.35	1.97
3.0	283	276	35.9	0.30	0.30	0.42	0.37	0.73	0.89	1.82	1.91	1.90
3.5	350	339	44.1	0.31	0.50	0.47	0.45	0.78	0.99	0.88	1.38	2.81
3.58	370	358	46.6	0.49	0.63	0.50	0.52	0.91	1.23	1.27	1.30	Breakthroug
4.0	406	394	51.2	0.51	0.57	0.79	0.61	0.96	1.32	1.40	1.30	1.65
4.5	426	414	53.8	0.56	0.59	0.66	0.59	0.89	1.16	1.39	1.20	1.95
5.0	461	449	58.4	0.78	0.60	0.72	0.69	0.95	1.16	1.34	1.37	1.55
5.5	463	451	58.6	0.75	0.71	0.83	0.60	1.07	1.12	1.35	1.17	1.62
6.0	488	476	61.9	0.77	0.75	0.74	0.62	0.95	0.98	1.36	1.13	1.83
6.28	496	484	62.9	End of run								

Oil in Place = 769.0 cc's = 94.6% Pore Volume, Connate Water = 43.5 cc's = 5.35% Pore Volume

Breakthrough Recovery (corrected) = 358 cc's = 46.6% Oil in Place

Total Recovery (corrected) = 484 cc's = 62.9% Oil in Place

TABLE 4-A

RECORDED DATA

Run No. 5 Slug Size: 8% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section								
				1	2	3	4	5	6	7	8	9
0.5	26.3	28.3	3.7	0.02	0.90	1.62	1.00	1.09				
1.0	48.1	48.1	6.3	0.03	0.67	0.28	0.86	1.36	1.61	1.72	1.33	
1.5	78	78	10.2	0.02	0.21	0.35	0.29	0.48	1.15	1.84	1.89	
2.0	152	152	19.8			2.25	2.12	0.80	1.03	0.88	0.76	0.82
2.17	184	182	23.8			1.17	2.18	1.77	1.42	1.20	0.83+	
2.5	217	213	27.8	0.13	0.19	0.32	0.68	2.16	1.80	1.78		
3.0	274	266	34.7	0.16	0.22	0.26	0.41	0.81	1.85	1.82	1.37	
3.5	329	318	41.5	0.23	0.32	0.25	0.44	0.72	0.94	1.20	2.85	
3.98	401	385	50.3	0.40	0.48	0.52	0.56	1.14	1.28	1.65	1.99	Breakthrough
4.5	427	411	53.7	0.54	0.48	0.57	0.58	0.95	1.30	1.46	1.96	
5.0	437	421	55.0	0.65	0.60	0.60	0.66	1.09	1.16	1.46	1.50	
5.5	439	423	55.2	0.62	0.67	0.72	0.53	1.05	1.19	1.41	1.42	
6.0	447	431	56.3	0.69	0.76	0.68	0.56	0.98	1.27	1.69	1.25	
6.42	469	453	59.1	End of run								

Oil in Place = 766 cc's = 94.64% Pore Volume, Connate Water = 4.34 cc's = 5.36% Pore Volume

Breakthrough Recovery (corrected) = 385 cc's = 50.3% Oil in Place

Total Recovery (Corrected) = 453 cc's = 59.1% Oil in Place

TABLE 5-A

RECORDED DATA

Run No. 6 Slug Size: 3% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section 1	2	3	4	5	6	7	8	9
0				0.66	0.98	1.05	0.99	0.99	0.99	1.02	1.12	1.08
0.25	15	15	2.0	0.10	0.58	0.95	1.07	1.16	0.99	1.05	0.91	1.09
0.75	45	45	6.0	0.16	0.15	0.25	0.79	1.10				
1.0	60	60	8.0	0.68	0.24	0.30	0.27	0.42	0.99	1.34	1.16	1.35
1.5	100	100	13.3	0.46	0.60	0.43	0.81	0.73	0.53	1.12	1.41	2.33+
1.75	120	120	15.9	0.46	0.52	0.63	0.66	1.15	0.84	0.77	1.25	2.27
2.0	148	148	19.7	0.48	0.48	0.56	0.79	1.08	1.09	0.78	1.48	1.86
2.25	175	174	23.1	0.29	0.38	0.33	0.82	0.92	1.29	0.85	1.23	1.79
2.5	205	203	27.0	0.20	0.41	0.33	0.58	1.00	1.42	1.12	1.17	1.99
3.0	267	264	35.1	0.32	0.43	0.34	0.40	0.54	0.76	2.13		
3.5	355	349	46.3	0.51	0.61	0.41	0.42	0.61	0.67	1.11	1.30	
3.58	370	364	48.3	Breakthrough								
4.0	405	399	53.0	0.72	0.68	0.61	0.64	0.87	0.74	1.13	1.76	
4.5	425	419	55.6	0.70	0.69	0.71	0.60	0.88	0.85	0.84	1.18	
5.0	450	444	59.0	0.67	0.92	0.58	0.72	0.93	0.84	1.15	0.94	
5.5	465	459	61.0	0.98	0.79	0.73	0.64	0.76	0.92	0.99	0.91	
5.87	480	474	62.9	1.01	0.89	0.85	0.59	0.86	1.06	0.86	0.96	End of run

Oil in Place = 753 cc's = 93.2% Pore Volume, Connate Water = 55.2 cc's = 6.8% Pore Volume

Breakthrough Recovery (corrected) = 364 cc's = 48.3% Oil in Place

Total Recovery (Corrected) = 474 cc's - 62.9% Oil in Place

TABLE 6-A

RECORDED DATA

Run No. 8 Slug Size: 1% Pore Volume

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section 1	2	3	4	5	6	7	8	9
0.25	12	12	1.6	0.93	1.28	0.87	0.85	1.18				
0.50	27	27	3.6	0.63	1.17	0.89	0.86	1.10	1.17	1.22	1.08	
1.0	51	51	6.7	0.49	0.57	1.02	1.03	1.17	1.33	1.31	1.20	
1.5	75	75	9.9	0.25	0.42	0.75	1.01	1.22	1.28	1.36	1.30	
2.0	101	101	13.3	0.23	0.35	0.52	1.00	1.30	1.42	1.33	1.50	
2.5	127	127	16.8	0.19	0.27	0.32	0.77	1.37	1.44	1.54	1.56	
3.0	156	156	20.6	0.30	0.15	0.24	0.50	1.34	1.49	1.57	1.76	
3.5	185	185	24.4	0.24	0.15	9.21	0.24	1.19	1.52	1.60	1.60	
4.0	220	219	28.9	0.26	0.21	0.22	0.16	0.44	1.38	1.81	1.49	
4.5	260	259	34.2	0.27	0.23	0.19	0.17	1.39	1.44	1.77	2.07	
5.0	314	312	41.2	0.28	0.40	0.25	0.26	0.42	0.59	0.88	1.16	
5.22	348	346	45.7	Breakthrough								
5.5	369	367	48.5	0.59	0.67	0.50	0.48	0.75	0.99	1.22	1.40	
6.0	389	387	51.1	0.76	0.60	0.55	0.54	0.79	0.99	1.14	1.47	
6.5	405	403	53.2	0.82	0.70	0.62	0.47	0.95	0.86	1.31	1.37	
7.0	426	424	56.0	0.90	0.69	0.56	0.58	0.81	0.96	1.12	1.33	
7.5	436	434	57.3	0.87	0.83	0.63	0.57	0.84	1.02	1.14	1.28	End of run

Oil in Place = 757 cc's = 94.8% Pore Volume, Connate Water = 41.7 cc's = 5.2% Pore Volume

Breakthrough Recovery (corrected) = 346 cc's = 45.7% Oil in Place

Total Recovery (corrected) = 434 cc's = 57.3% Oil in Place

TABLE 7-A

RECORDED DATA

Run No. 9 Slug Size: 0% Pore Volume (Waterflood)

Time	Oil Prod'n.	Oil Prod'n. (Corrected)	Oil Prod'n. % O.I.P.	Pressure Ratio in Section 1	2	3	4	5	6	7	8	9
0.25	11	11	1.5	1.29	1.01	0.94	0.91	0.90	0.93	0.96	0.85	1.16
0.50	22	22	2.9	0.89	1.20	0.91	1.02	1.07	1.06	1.06	0.87	2.26
1.0	45	45	6.0	0.38	1.08	1.19	1.09	1.01	1.11	1.10	0.95	1.37
1.5	71	71	9.4	0.27	0.64	1.25	1.14	1.02	1.11	1.10	0.88	
2.0	97	97	12.8	0.14	0.34	0.82	1.26	1.18	1.21	1.55	1.17	
2.5	126	126	16.7	0.18	0.25	0.48	1.10	1.30	1.28	1.31	1.10	
3.0	156	156	20.6	0.20	0.23	0.35	0.55	1.20	1.38	1.41	1.28	
3.5	190	190	25.1	0.20	0.25	0.34	0.36	0.77	1.37	1.59	1.39	
4.0	225	225	29.8	0.28	0.23	0.31	0.34	0.54	0.73	1.64	1.89	
4.5	275	275	36.4	0.27	0.29	0.43	0.31	0.51	0.59	0.91	1.35	
4.75	315	315	41.7	Breakthrough								
5.0	333	333	44.0	0.51	0.51	0.71	0.60	0.77	0.93	1.26	1.27	
5.5	355	355	47.0	0.46	0.58	0.85	0.78	0.98	0.99	1.34	1.05	
6.0	368	368	48.7	0.54	0.58	0.85	0.76	0.93	0.94	1.24	1.03	
6.5	378	378	50.0	0.61	0.68	0.78	0.74	0.90	0.89	1.28	1.07	
7.0	400	400	52.9	0.69	0.64	0.85	0.71	0.87	0.89	1.22	1.03	
7.5	430	430	56.9	0.67	0.58	0.98	0.64	0.93	0.91	1.08	1.00	End of run

Oil In Place = 756 cc's = 93.9% Pore Volume, Connate Water = 49 cc's = 6.1% Pore Volume

Breakthrough Recovery (corrected) 315 cc's = 41.7% Oil in Place

Total Recovery (corrected) = 430 cc's = 56.9% Oil in Place

TABLE 8-A

RECORDED DATA

Run No. 10   Slug Size: 2% Pore Volume

	Oil	Oil Prod'n.	Oil Prod'n.	Pressure Ratio in Section								
Time	Prod'n.	(Corrected)	% O.I.P.	1	2	3	4	5	6	7	8	9
0.25	9.8	9.8	1.3	0.80	1.01	0.94	0.99	1.00				
0.5	19	19	2.5	0.27	0.96	1.10	1.10	1.04	1.11	1.05	1.02	
1.0	43	43	5.6	0.31	0.33	1.00	1.22	1.18	1.23	1.22	1.13	
1.5	66	66	8.6	0.12	0.28	0.44	0.71	1.38	1.46	1.25	1.26	
2.0	91	91	11.9	0.11	0.32	0.74	0.54	0.78	1.47	1.43	1.32	
2.5	120	120	15.7	0.16	0.30	0.74	0.91	0.71	1.07	1.57	1.40	
3.0	152	152	19.9	0.22	0.17	0.36	1.19	0.93	0.90	1.19	1.59	
3.5	186	185	24.2	0.16	0.18	0.32	0.61	1.30	1.14	1.16	1.32	
4.0	227	226	29.6	0.16	0.24	0.29	0.44	0.68	0.87	1.45	1.44	
4.5	287	284	37.2	0.29	0.30	0.31	0.49	0.57	0.77	0.88	1.06	
4.92	364	360	47.2	Breakthrough								
5.0	366	362	47.4	0.36	0.34	0.55	0.56	1.00	1.13	1.11	1.06	1.52
5.5	395	391	51.2	0.41	0.51	0.74	0.76	0.98	1.17	1.25	1.11	1.65
6.0	416	412	54.0	0.54	0.52	-.66	0.77	0.92	1.10	1.19	1.13	1.62
6.5	432	428	56.1	0.60	0.58	0.69	0.72	0.96	0.78	1.31	1.12	
7.0	444	440	57.7	0.59	0.64	0.66	0.67	0.92	0.86	1.15	1.13	
7.33	465	461	60.4	End of run								

Oil in Place = 763cc's = 94.5% Pore Volume, Connate Water - 44.2 cc's = 5.47% Pore Volume

Breakthrough Recovery (corrected) = 360 cc's = 47.2% Oil in Place

Total Recovery (corrected) = 461 cc's = 60.4% Oil in Place

B29786